# ALBERTA

# ENERGY RESOURCES CONSERVATION BOARD

# DECISIONS

1983

# DECISIONS

## ISSUED IN 1983

| NUMBER | APPLICATION NUMBER | TITLE | DATE OF ISSUE |
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| D 83-1 | 821106 | WELL LICENCE<br>CHAMPLIN CANADA | 10 FEBRUARY 1983 |
| D 83-2 | 820420 | ONE LEGAL SUBDIVISION DRILLING SPACING UNITS -<br>CAMPBELL - NAMAO FIELD<br>CANADA NORTHWEST ENERGY | 4 MARCH 1983 |
| D 83-3 | 820934 AND 820935 | PERMITS TO CONSTRUCT ETHYLENE GLYCOL PIPELINES - PRENTISS TO BLACKFALDS<br>UNION CARBIDE CANADA | 22 MARCH 1983 |
| D 83-4 | | 1982 ADMINISTRATION FEE APPEALS<br>REVIEW OF PROPOSED REVISIONS TO THE ADMINISTRATION FEE SYSTEM | 4 APRIL 1983 |
| D 83-5 | 821217 | OVERBURDEN DISCARD SITE<br>SYNCRUDE CANADA | 31 MARCH 1983 |
| D 83-6 | PROC. 821207 | PUBLIC MEETING TO CONSIDER CONCERNS REGARDING THE DEVELOPMENT OF THE PROPOSED SADDLE RIDGE AREA | 8 JUNE 1983 |
| D 83-7 | 810932 | TRANSMISSION LINES -<br>GENESEE AREA<br>THE CITY OF EDMONTON | 18 MAY 1983 |
| D 83-8 | | LOCAL INTERVENERS' COSTS HEARINGS - JUMPING POUND GAS PROCESSING PLANT, QUIRK CREEK GAS PROCESSING PLANT AND THE PROPOSED MOOSE AND WHISKEY FIELDS PIPELINE HEARINGS | 30 JUNE 1983 |
| D 83-9 | | LOCAL INTERVENERS' COSTS HEARINGS - RESPECTING THE RAM RIVER GAS PROCESSING PLANT AND THE STRACHAN GAS PROCESSING PLANT HEARINGS | 30 JUNE 1983 |
| D 83-10 | 821089, 830012 AND 830087 | SOUR GAS PROCESSING -<br>EAST-CENTRAL ALBERTA<br>VOYAGER PETROLEUMS<br>SIGNALTA RESOURCES | 30 JUNE 1983 |
| ADDENDUM D 83-10 | 821089 | GAS PROCESSING PLANT -<br>EAST CENTRAL ALBERTA<br>VOYAGER PETROLEUMS | 22 AUGUST 1983 |

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| NUMBER | APPLICATION NUMBER | TITLE | DATE OF ISSUE |
|---|---|---|---|
| D 83-11 | 810924, 810925, 810926, AND 820251 | SOUR GAS PIPELINES<br>REINJECTION PIPELINE<br>FUEL GAS PIPELINE -<br>BRAZEAU RIVER<br>WEST PEMBINA AREA<br>HUDSON'S BAY OIL AND GAS | 14 JULY 1983 |
| D 83-12 | PROC. 821137 | PUBLIC INQUIRY TO CONSIDER POTENTIAL CONFLICTS BETWEEN DEVELOPMENT OF SOUR GAS RESERVES AND RESIDENTIAL DEVELOPMENT -<br>OKOTOKS AREA | 29 JULY 1983 |
| D 83-13 | 820346 | GAS PROCESSING PLANT -<br>OKOTOKS<br>CANADIAN OCCIDENTAL PETROLEUM | 29 JULY 1983 |
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| D 83-15 | 820874 AND 820889 | TRANSMISSION LINE FACILITIES -<br>NORTH EAST CALGARY AREA<br>TRANSALTA UTILITIES CORPORATION<br>THE CITY OF CALGARY | 18 AUGUST 1983 |
| D 83-16 | 830215, 830216, 830217, 830218 AND 830219 | TO CONSTRUCT CONDENSATE AND BITUMEN BLEND PIPELINES AND PUMPING FACILITIES -<br>FORT KENT AREA<br>TO CONSTRUCT PUMPING FACILITIES -<br>BELLIS AREA<br>ALBERTA ENERGY COMPANY | 8 JULY 1983 |
| D 83-17 | 830165, 830166 AND 830167 | TO DRILL A WELL AND CONSTRUCT TWO PIPELINES -<br>CROSSFIELD-AIRDRIE AREA<br>ICG RESOURCES | 29 JULY 1983 |
| | 830460 AND 830461 | DRILLING SPACING UNIT AND TO DRILL A WELL -<br>CROSSFIELD-AIRDRIE AREA<br>CANADIAN OCCIDENTAL PETROLEUM | |
| | 830488 AND 830489 | CONSTRUCT TWO PIPELINES -<br>CROSSFIELD-AIRDRIE AREA<br>PETROGRAS PROCESSING | |

DECISIONS

| NUMBER | APPLICATION NUMBER | TITLE | DATE OF ISSUE |
|---|---|---|---|
| D 83-18 | 820632 | WATERFLOOD - BIGORAY CARDIUM B POOL CHEVRON CANADA | 22 JULY 1983 |
| D 83-19 | 830246 | HYDROCARBON MISCIBLE FLOOD - JUDY CREEK BEAVERHILL LAKE A POOL ESSO RESOURCES | 6 OCTOBER 1983 |
| D 83-20 | 830041 | GAS PROCESSING PLANT - BRAZEAU RIVER FIELD PETRO-CANADA INC. | 19 AUGUST 1983 |
| D 83-21 | 830620 | PHASED DEVELOPMENT OF THE COLD LAKE OIL SANDS PROJECT ESSO RESOURCES | 25 AUGUST 1983 |
| D 83-22 | 830603 | PROPOSED MOOSE AND WHISKEY PIPELINES AND RELATED FACILITIES - KANANASKIS AREA SHELL CANADA | 8 SEPTEMBER 1983 |
| D 83-23 | PANEL REPORT | 1983 ADMINISTRATION FEE APPEAL | 23 SEPTEMBER 1983 |
| D 83-24 | 830222 | TERTIARY MISCIBLE SCHEME - WIZARD LAKE D-3A POOL TEXACO CANADA | 28 SEPTEMBER 1983 |
| D 83-25 | 830736 AND 830737 | SOUR GAS PIPELINE FUEL GAS PIPELINE - BENJAMIN FIELD PETRO-CANADA | 31 OCTOBER 1983 |
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| D 83-27 | 830588 AND 830662 | EXPERIMENTAL IN SITU HEAVY OIL SCHEME - LINDBERGH AREA DOME PETROLEUM | 27 OCTOBER 1983 |
| D 83-28 | 830394 | TO ALLOW THE TRANSPORT OF HIGH VAPOUR PRESSURE PRODUCTS AND CONSTRUCT HIGH VAPOUR PRESSURE PIPELINES - FORT SASKATCHEWAN, MORINVILLE AND SWAN HILLS AREAS FEDERATED PIPE LINES | 17 NOVEMBER 1983 |

## DECISIONS

| NUMBER | APPLICATION NUMBER | TITLE | DATE OF ISSUE |
|---|---|---|---|
| D 83-29 | 830567 AND 830883 | GAS CYCLING SCHEMES | 7 DECEMBER 1983 |
| | 830836, 830873 AND 831088 | SOUR GAS PIPELINES | |
| | 830874 AND 831086 | INJECTION PIPELINES | |
| | 830875 AND 831087 | FUEL GAS PIPELINES - | |
| | | BRAZEAU RIVER-WEST PEMBINA AREA<br>PETRO-CANADA<br>HUDSON'S BAY OIL AND GAS | |
| D 83-C | 820385 | Mercoal Coal Project | |

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATION FOR A WELL LICENCE BY CHAMPLIN CANADA LTD.

Decision D 83-1
Application 821106

# 1 INTRODUCTION

## 1.1 The Application

Champlin Canada Ltd. (Champlin) applied for a well licence to re-enter the abandoned well known as AMOCO LANAWAY 11-16-35-3 for the purpose of recompleting the well in the Viking Formation to obtain oil production. The application is pursuant to section 17(1) of the Oil and Gas Conservation Act and section 2.020 of the Oil and Gas Conservation Regulations, and the well is located in legal subdivision 11 of section 16, township 35, range 3, west of the 5th meridian (Lsd 11-16-35-3 W5M). Champlin stated its rights to the minerals were provided by a farm-out agreement with Amoco Canada Petroleum Company Ltd. (Amoco). Champlin indicated Amoco's surface lease had expired following abandonment and restoration of the location and subsequent granting of a reclamation certificate. The applicant indicated it was unsuccessful in negotiating a new surface lease agreement with the owner and occupant of the land, Susanna and George Tingle (the Tingles), who were also claiming ownership of the existing production casing in the abandoned well.

The surface owner and occupant filed an objection to the application and requested the matter be considered at a hearing.

The attached figure shows the proposed well site, dimensions of the previously leased site, the Tingles' home, and surrounding area.

## 1.2 The Hearing

A public hearing to consider this application was held on 11 January 1983 at Innisfail, Alberta, with G. J. DeSorcy, P.Eng., C. J. Goodman, P.Eng., and E. J. Morin, P.Eng., sitting.

THOSE WHO APPEARED AT THE HEARING

| Principals and Representatives (Abbreviations Used In Report) | Witnesses |
|---|---|
| Champlin Canada Ltd. (Champlin)<br>J. F. Curran | L. P. Malowany, P.Eng.<br>K. S. Raskin, P.Geol.<br>A. J. Weir |
| S. M. and G. Tingle (the Tingles)<br>G. Noval | S. M. Tingle<br>G. Tingle |
| Energy Resources Conservation Board staff<br>K. F. Miller<br>G. D. Agnew<br>M. Semchuck | |

1.3 Preliminary Matters

The Board believes it appropriate to address three preliminary matters. First, the Board notes for the record, that since applying to recomplete the subject well, the applicant has changed its corporate name from Champlin Petroleum Company to Champlin Canada Ltd. The second matter relates to argument by the Tingles that they own the casing in the abandoned well. In response, the applicant submitted that the person entitled to recover the minerals underlying the drilling spacing unit owns the casing. The Board is not making any ruling or declaration regarding who has a proprietary interest in the casing for two reasons:

(1) such a ruling or declaration is not necessary to enable the Board to make a decision respecting the specific application before it, and
(2) a Board hearing is not the proper forum before which such an issue should be raised as the Board considers the matter to be of a civil nature.

The third matter concerns the submission by the Tingles that the application should be denied because the applied-for location is outside the oil target area prescribed by Board Order No. SU 1088.

flaring regularly occur. Champlin indicated, in response to questioning, that it saw no reason why it could not locate all of its surface production equipment, except the pumping unit, in a suitable area away from the Tingles' residence.

The applicant stated it would consider alternative routes for its access road if the applied-for route was not acceptable to the Tingles and suggested an alternative access road from the western portion of the northwest quarter of section 16.

Champlin affirmed it was prepared to negotiate mutually acceptable arrangements and proper mitigative measures with the surface owners to reduce impact on the Tingles and their surface land use. Champlin concluded that such efforts would furnish a satisfactory resolution, thereby precluding the Board's need to provision any well licence granted to the applicant.

## 2.2 Views of the Tingles

The Tingles objected to Champlin's application because the proposed well site was in close proximity to their residence. The interveners said that one of their main concerns was the visual impact the proposed 11-16 location would cause, as it would interrupt the presently unobstructed view from their residence. The Tingles contended that noise, potential odours, and flaring of solution gas at the well site, would also cause adverse effects.

The interveners said another main concern regarding Champlin's application was the routing of the access road and, in particular, maintaining ownership and control of their private road which would comprise part of the proposed access road. The Tingles advised they had previously negotiated a suitable contractual arrangement with Amoco for the joint use of their private roadway and indicated a willingness to negotiate a similar arrangement with Champlin.

The Tingles suggested an alternative location for Champlin's proposed well would be in the northeast corner of the northwest quarter of section 16. Its associated access road would utilize an existing road across the north boundary of section 16, then would extend south to the well site from the northeast corner of the subject quarter. The Tingles thought this alternative well site and associated access road would be preferable for the following reasons:

- o it would be located on uncultivated bush land,
- o it would be out of view from their residence, and
- o it would minimize the negative aspects of Champlin's proposed operations, including noise, odour, and flaring of solution gas.

The interveners stated that if the proposed well cannot be drilled in the northeast corner of the subject quarter section, then production equipment, excluding the pumping unit, should be located off-lease in

the bush northeast of their residence. The Tingles suggested the exact location for the off-lease production facilities could be determined through further on-site negotiation with Champlin. The interveners affirmed their willingness to negotiate several specific items including:

- o screening the well site,
- o noise and odour reduction,
- o electrification, and
- o specific terms regarding access road usage.

The Tingles concluded that if Champlin was granted a licence to re-enter the proposed 11-16 well, licence provisions should assure not only proper maintenance of the production facility, but also that the site remain as a single-well facility, thereby precluding the development of a multi-well battery at the well site.

## 2.3 Views of the Board

The Board, having regard for the existing wells in the area, recognizes that a well on the northwest quarter of section 16 would assist in delineating the oil reserves in the area. Furthermore, if it was successfully completed as an oil well, it would increase the productive capacity of the Garrington Viking pools. A successful well could verify substantial quantities of oil, but the Board is unable to determine any specific value because of the speculative nature of the prospect. For the above reasons, the Board sees justification for a well on the northwest quarter of section 16, provided its impact on the Tingles and the land surface would not be so great as to require denial of the application.

The Board notes that Champlin is required to re-enter the 11-16 abandoned well and attempt to recomplete it in the Viking Formation to fulfill its farm-in commitment to Amoco.

The Board understands the concerns of the Tingles respecting visual impact, the adverse effect created by a production facility adjacent to their residence, and the joint utilization of the proposed access road. Having regard for these concerns expressed by the interveners, the proximity of the proposed well site to their residence, and the economic advantage (as compared to a new well) which would accrue to Champlin if it is allowed to re-enter the abandoned well, the Board believes that the minimum mitigative measure should involve the careful location of all of Champlin's surface production facilities,

excluding the pumping unit, to an off-lease location mutually acceptable to the applicant and landowners. The Board notes Champlin's stated willingness to consider such an arrangement. Consequently, the Board will assess the impacts that would result if the well was re-entered and completed and if the production facilities and the access to them were relocated away from the Tingles' residence. If the Board finds the impacts that would result from this "modified proposal" to be reasonably acceptable, it will approve the application.

The Board recognizes that the modified proposal would involve some nuisance and inconvenience to the Tingles during the re-entry and completion phase. However, the inconvenience of having a drilling site located close to their residence would be limited to a short period of time during the drilling, completing, and, if necessary, testing of the well. If a commercial well is encountered and Champlin relocates all surface production facilities, excluding the pumping unit, to a mutually acceptable location, the ongoing impact on the Tingle residence would relate primarily to the existence of the pumping unit. The Board recognizes that a pumping unit is a significant piece of equipment but believes the impact of such a unit would be reasonably acceptable provided certain conditions were adhered to. These include:

- adequately screening the pumping unit with trees,
- properly maintaining the facility,
- installation of an underground muffler system,
- electrification of the pump as soon as the necessary power is available, and
- ensuring that the proposed site would remain as a single well.

In the Board's view, having regard for the foregoing, the impact of the proposed 11-16 well would not be so great as to require denial of the application. The Board expects that negotiations between the applicant and the Tingles would result in the selection of a suitable off-lease location for production facilities, and a satisfactory route of access and road design. Furthermore, the Board notes the applicant's expectations with respect to possible pipelining of production and the possibility of a central battery, and would expect Champlin to carry out discussions and negotiations with other operators, as appropriate, to accomplish such objectives.

# 3 OTHER MATTERS

## 3.1 Target Areas

As was noted in 1.3 of this report, the Board believes the matter of the target area for the proposed well should be addressed. The 11-16 well was licensed, drilled, and abandoned prior to the issuance of Board Order No. SU 1088. This order, which relocated the oil target area for quarter-section spacing from the central portion of the quarter section to the northeast quadrant, applied only to new wells which commenced drilling after 1 September 1981. Since AMOCO LANAWAY 11-16-35-3 was drilled prior to 1 September 1981, the Board considers it, notwithstanding its abandoned status, to be a well, and therefore on target for oil produced from all formations encountered in the borehole when the well was drilled. This target provision was assigned in accordance with the pre-existing rules under which the well was originally drilled.

## 3.2 Mineral Rights

The Board notes that the Alberta Petroleum and Natural Gas Lease No. 30169, farmed out by Amoco to Champlin, is a 10-year lease, dated 6 February 1973. Having regard for this, the Board would not grant a well licence for the 11-16 location to the applicant until such time as Champlin had satisfied the Board that it has a continuing right to the minerals underlying the northwest quarter of section 16-35-3 W5M.

# 4 DECISION

Having considered the evidence, including the potential impacts on the surface owners and the commitments by the applicant to negotiate and mitigate impacts, the Board is prepared to grant the application to Champlin Canada Ltd. to re-enter the abandoned well known as AMOCO LANAWAY 11-16-35-3. This decision is contingent on Champlin satisfying the Board that it continues to have a right to the minerals underlying the subject land. The Board will issue a well licence in due course and will make the well licence subject to the following special conditions:

(1) If the well is a successful oil well, all permanent surface production facilities, excluding the pumping unit, shall be located off-lease at a location that is mutually agreed to by the surface owners and is satisfactory to the Board.

(2) After initial recompletion and testing of the well, no surface production facilities other than the 11-16 wellhead and pumping unit, shall be installed at the well site.

(3) If a pumping unit is installed at the well site, it shall screened by trees to the satisfaction of the Board.

(4) An underground muffler system shall be installed and electrification of the pumping unit shall take place as soon as practical.

(5) Production facilities shall be inspected regularly and shall remain adequately maintained at all times.

ISSUED at Calgary, Alberta on 10 February 1983

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy

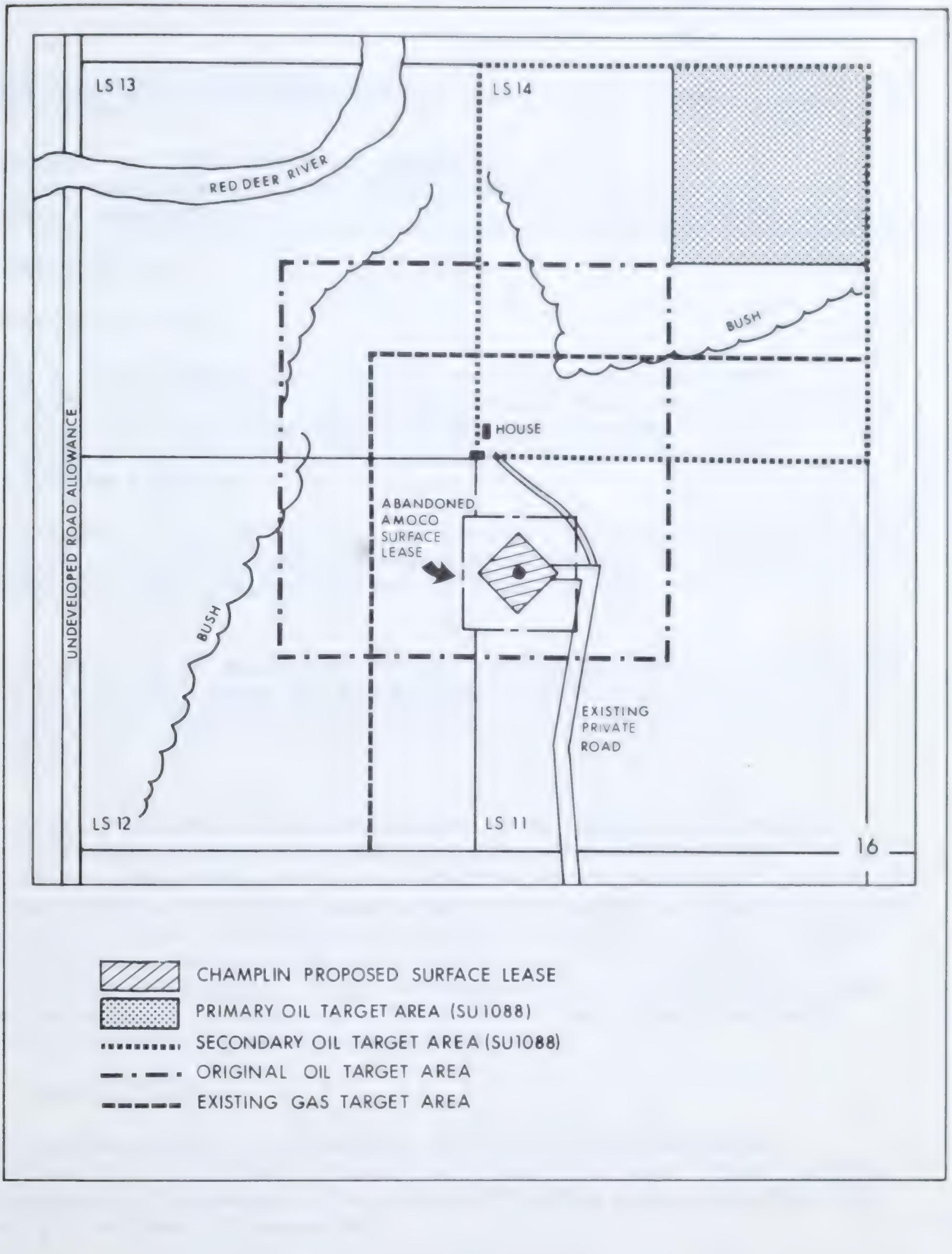
G. J. DeSorcy, P.Eng.

C. J. Goodman

C. J. Goodman, P.Eng.

E. J. Morin

E. J. Morin, P.Eng.
Acting Board Member




CHAMPLIN GARRINGTON PROPOSED LOCATION

LSD 11-16-35-3W5M

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATION BY CANADA NORTHWEST ENERGY LTD
ONE LEGAL SUBDIVISION DRILLING SPACING UNITS — Decision D 83 - 2
CAMPBELL - NAMAO FIELD — Application No. 820420

1. INTRODUCTION

1.1 The Application

Canada Northwest Energy Ltd. applied pursuant to section 4.030 subsection (1) of the Oil and Gas Conservation Regulations to establish one legal subdivision (Lsd) drilling spacing units (DSU) for the production of oil from the Lower Mannville Formation for lands described as follows:

o The North half of Section 12, the east half and legal subdivisions 13 and 14 of Section 13 and the east half of Section 14 in Township 54, Range 25, W4M, currently subject to 2 Lsd spacing,

o The west half of Section 18 and the south-west quarter of Section 19 in Township 54, Range 24, W4M and the south half of Section 12 in Township 54, Range 25, W4M, currently subject to quarter section spacing.

The target areas would be in the centre of the legal subdivision in accordance with section 4.020 subsection(2) of the Oil and Gas Conservation Regulations with the exception of the south west quarter of Section 19 where the target area would be the north west quadrant of the legal subdivision in accordance with Board Order No. SU 1088. The area of application, the existing wells and the structure contours of the Campbell-Namao Blairmore J Pool are shown on the attached figure taken from the applicant's submission. Residential development and major production facilities are also indicated.

1.2 The Intervention

Three interventions were filed when the subject application was advertised for objections. However only one intervener filed a written intervention in response to the notice of hearing and appeared at the hearing to address his concerns.

## 1.3 The Hearing

On 1 February 1983, a public hearing of the application was held in Edmonton with G.J. DeSorcy, P.Eng.; C.J. Goodman, P.Eng.; and N.A. Strom, P.Eng. sitting.

THOSE WHO APPEARED AT THE HEARING

| Principals and Representatives<br>(Abbreviations used in Report) | Witnesses |
|---|---|
| Canada Northwest Energy Ltd.<br>(Canada Northwest)<br>M. Skinner | E. Saruk, P.Eng.<br>R. F. Webster, P. Geol. |
| Karbonik, Tym and Koziak<br>(Karbonik) | G. Karbonik |
| Energy Resources Conservation Board<br>(Board Staff)<br>K. F. Miller<br><br>R. J. Willard, P.Eng.<br><br>H. J. W. Piet, C.E.T. | |

## 2. CONSIDERATION OF THE APPLICATION

### 2.1 Views of the Applicant

Canada Northwest stated that, upon acquiring the assets of Oakland Petroleum Limited in the Campbell Namao Blairmore J Pool, it undertook reservoir studies and attempted reworks in most of the wells in order to increase productivity. The overall success rate was disappointing and from its experience Canada Northwest believed that the best method of improving oil recovery would be to drill some replacement wells and infill drill other locations.

Canada Northwest's studies showed that the pool has an active aquifer and an overlying gas cap with the limits of the pool as shown on the attached figure. Owing to shale stringers the reservoir porosity and permeability is highly variable and, as a result, the thickness of the oil leg and the position of the gas-oil and oil-water interfaces varies by as much as 3.5 and 3 metres respectively. Availability of one Lsd spacing would permit drilling of the most favorable locations and result in much improved oil recovery.

Canada Northwest submitted that the present surface facilities including separation, oil tankage and gas compression located on farm lands in Lsd 13 of Section 12 were adequate to serve the six or seven additional wells that it intended to drill. Also gas conservation for sale or re-injection would continue and compressor capacity at the battery located in Lsd 13 of Section 12 was sufficiently oversized to handle all additional volumes of gas.

Referring to its near term plans, Canada Northwest commented that following approval it intended to drill wells in Lsd 14 of Section 12, Lsd 2 of Section 13 and Lsd 4 of Section 19. These locations, it believed had above average possibilities of success. Depending on the degree of success, Canada Northwest suggested it might subsequently drill wells in Lsd 1 of Section 14 and in the southeast quadrant of Section 12. Respecting the lands owned by Karbonik (Lsds 15 and 16 of Section 13), Canada Northwest noted that the oil in Lsd 16 would be drained by the existing directional well for which the surface location is in Lsd 12 of Section 14. Canada Northwest had no current plans to redrill the previously abandoned Lsd 15 well but could not guarantee that it would not wish to drill that location at some future date. In regard to the possibility of using directional drilling to reduce land surface use problems, Canada Northwest indicated that it preferred to drill straight holes whenever possible because directional wells were much more costly to drill (35 per cent higher) and far more costly to operate and service.

Respecting land surface impact, the applicant stated that the area was generally used for agriculture but there were small acreage holdings in Lsds 9 and 10 of Section 13 (R.25) and Lsds 11 and 14 of Section 18 (R.24). Canada Northwest noted, however, that it had not received any complaints concerning its operations from any of these acreage residents nor any other residents in the general area.

## 2.2 Views of the Intervener

Karbonik opposed the application on the grounds that additional drilling activity might reduce the subdivision potential of Lsds 15 and 16 in Section 13. Karbonik considered the land had subdivision possibilities for either residential, commercial or small acreage development and that this would be pursued when the general economic climate improved. The intervener further stated that drilling activity taking place on land surrounding his parcel might also reduce the land value. He acknowledged, however, that the existing wells in the surrounding lands were there at the time he had acquired his lands.

## 2.3 Views of the Board

The Board considers the Campbell Namao Blairmore J Pool to be a very heterogeneous reservoir containing shale stringers and permeability restrictions that may be expected to severely limit the drainage capability of individual wells. The Board therefore agrees with the applicant that the proposed reduced spacing should considerably enhance the potential for improved oil recovery as additional wells would drain reserves from those reservoir sections that could not be drained by the existing wells.

The Board concludes that increased energy resource conservation would be achieved if the reduced spacing density is approved and the applicant follows through with its stated plans for drilling.

The Board observes that some acreage subdivision has occurred within the pool boundaries and that wells have been drilled directionally to avoid conflicts with these developments. The Board also notes that the applicant does not have any plans for drilling Lsd 15 of Section 13, and also that it would have to approach Karbonik for surface access and to obtain a well license if it decided to proceed. At that time, if it ever occurs, Karbonik would have the right to deal with specific impacts that might arise.

Having regard for the conservation benefits that may be achieved, the general indications that the applicant has adhered to good "housekeeping" practices so as to avoid adverse impacts on local residents, and that licensing of an individual well will provide further opportunity for a landowner to negotiate directly with Canada Northwest respecting any specific concerns, the Board concludes that the application for reduced well spacing should be granted.

3. DECISION

The Board grants the application and will issue a well spacing order reflecting the changes applied for.

Issued at Calgary, Alberta on 4 March 1983.

ENERGY RESOURCES CONSERVATION BOARD

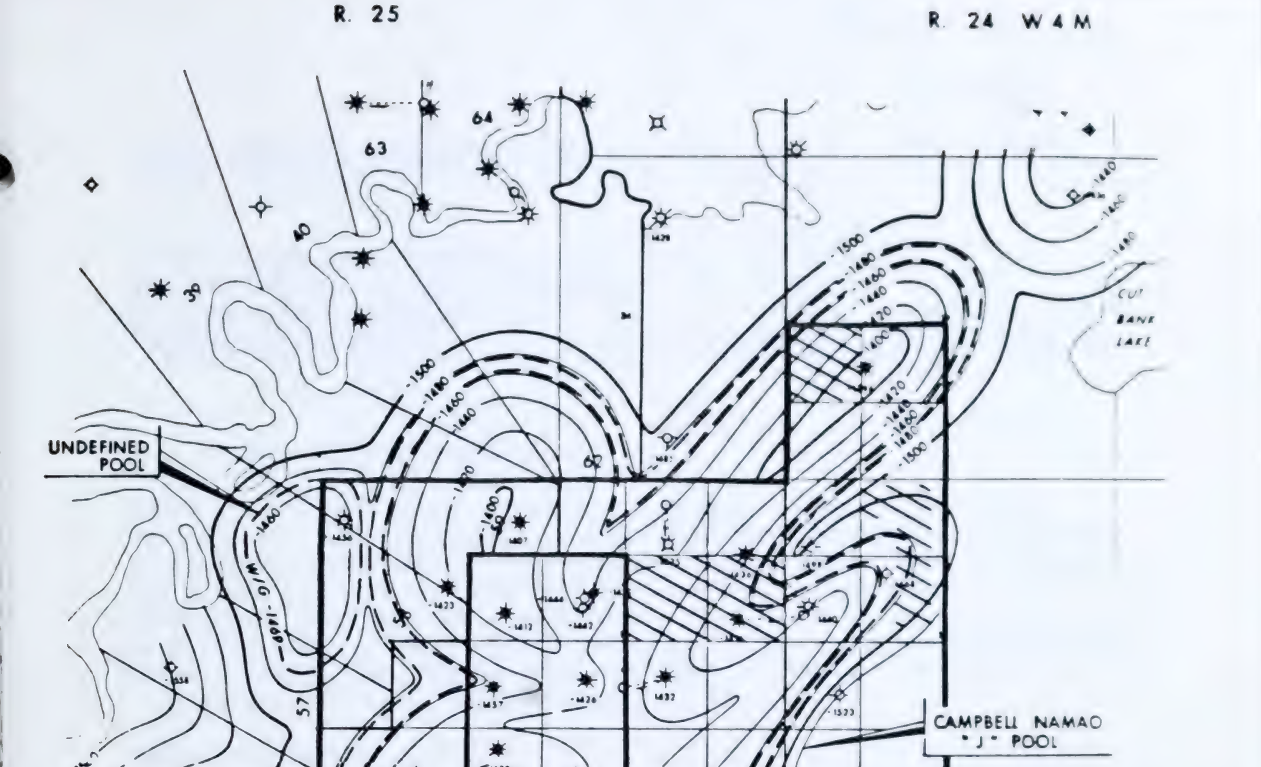
G. J. DeSorcy

G. J. DeSorcy, P.Eng.
Vice Chairman

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

N. A. Strom, P.Eng.
Board Member




AREA OF APPLICATION SHOWING
STRUCTURE CONTOURS, TOP OF THE BLAIRMORE FORMATION

LEGEND

AREA OF APPLICATION No. 820 420

URBAN DEVELOPMENT WITHIN AREA OF APPLICATION

PRODUCTION AND GATHERING FACILITIES

BLAIRMORE GAS/OIL WELL

GAS INJECTION WELL

BLAIRMORE CAPPED GAS WELL

SURFACE LOCATION

ABANDONED WELL

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

UNION CARBIDE CANADA LIMITED
APPLICATIONS FOR PERMITS TO CONSTRUCT
ETHYLENE GLYCOL PIPELINES FROM
PRENTISS TO BLACKFALDS

Decision D 83-3
Applications 820934 and 820935

## 1 THE APPLICATIONS AND HEARING

Union Carbide Canada Limited applied, pursuant to Section 4 of the Pipeline Act, for permits to construct two pipelines for the transmission of polyester-grade and antifreeze-grade ethylene glycol from its glycol plant near Prentiss to a proposed rail car loading terminal at Blackfalds. The attached figure shows the route of the proposed pipelines, alternative routes investigated by the applicant, the Prentiss plant location, the proposed rail car loading terminal, the Town of Blackfalds, and certain major features of the area.

Application 820934

The applicant proposed to construct approximately 18.5 kilometres (km) of 114.3-millimetre outside diameter stainless steel pipeline for the transmission of polyester-grade ethylene glycol from its plant at legal subdivision 14 of section 30, township 39, range 25, west of the 4th meridian (glycol plant), to the proposed Blackfalds rail car loading terminal in Lsd 11-26-39-27 W4M.

Application 820935

The applicant proposed to construct approximately 18.5 km of 168.3-millimetre outside diameter carbon steel pipeline for the transmission of antifreeze-grade ethylene glycol from the plant to the terminal.

The applications were considered by the Board at a public hearing in Red Deer on 15 and 16 February 1983, with G. J. DeSorcy, P.Eng., V. E. Bohme, P.Eng., and C. J. Goodman, P.Eng., sitting.

Interventions in opposition to the applications were filed by Preserve Agricultural Land (PAL); Blackfalds Mobile Park Ltd. owned and operated by the Hollands; Mr. and Mrs. J. Holland, and Mr. and Mrs. L. Holland. Interventions in support of the applications were filed by CP Rail, the Town of Blackfalds, and the Blackfalds and District Chamber of Commerce.

Mr. D. Johnstone filed a written intervention with the Board but did not present it at the hearing. He attended the hearing to cross-examine the applicant.

The table lists those who appeared at the hearing, along with abbreviations used in this report.

Table 1 THOSE WHO APPEARED AT THE HEARING

| Principals and Representatives (Abbreviations used in Report) | Witnesses |
|---|---|
| Union Carbide Canada Limited<br>(Union Carbide)<br>N. McDermid | D. C. Champ, P.Eng.<br>W. Lindley, P.Eng.<br>B. Mennie, P.Eng.<br>R. Piper, P.Eng.<br>D. G. Colley, P.Eng.<br>of Western Research |
| Preserve Agricultural Land<br>(PAL)<br>B. Vogel<br>L. Duncan | G. Friesen<br>R. N. Pocock<br>D. Chessor<br>E. Huss |
| Blackfalds Mobile Park Ltd.<br>Mr. and Mrs. J. Holland<br>Mr. and Mrs. L. Holland<br>(the Hollands)<br>B. Vogel | J. Holland<br>L. Holland |
| CP Rail<br>(CP)<br>M. Szel | R. Foot<br>L. Fortin |
| Town of Blackfalds<br>(Town)<br>D. Koller | D. Koller<br>E. Svederus<br>J. Rogers |
| Blackfalds and District Chamber of Commerce (Chamber)<br>W. Tutty | W. Tutty |
| D. Johnstone<br>R. Hicks | |
| Alberta Environment staff<br>D. Bratton<br>T. Bossenberry | |
| Energy Resources Conservation Board staff<br>K. F. Miller<br>J. D. Dilay, P.Eng.<br>J. K. Moloney | |

## 2 PRELIMINARY MATTERS

### 2.1 Standing of Certain Interveners

At the outset, Union Carbide moved for a declaration that the Blackfalds Mobile Park Ltd. and the Hollands were without standing to intervene in the hearing. It argued that the concerns of the Hollands, expressed in their filed intervention, related to the proposed rail car loading terminal and, since the marketing terminal does not form part of the subject matter of the proceeding, and since the Hollands' property is located some distance from the proposed pipelines, the Hollands would not be adversely affected by the pipelines. Union Carbide argued that the Board's jurisdiction extended to the pipelines but that the approval of the loading terminal was within the jurisdiction of other regulatory authorities, and therefore the Hollands had no standing.

Counsel for the Hollands, in response to the motion, urged the Board not to adopt the view of Union Carbide for separate consideration of the pipelines from the loading terminal, but rather to view the terminal and pipelines as being one.

The Board, after considering the arguments of both parties and noting that the evidence of the applicant was clear that, if the pipelines were constructed the terminal would be built, concluded that construction of the terminal would flow as a natural consequence from a decision approving the pipelines. Furthermore, if the terminal were built, the Hollands would be concerned with the effect on their property near the terminal. The Board ruled that the Hollands could be directly and adversely affected by a decision of the Board in this proceeding and accordingly had status as interveners.

### 2.2 Request for Additional Information and Adjournment

In its application Union Carbide stated, in part,

> "The need for the pipelines arises entirely from our inability to negotiate competitive transportation rates with the Canadian National Railway."

On the basis of this statement, on 2 February 1983, counsel for the Hollands requested documents and materials in the possession of Union Carbide pertaining to:

(a) a cost-benefit analysis of the alternatives of constructing the proposed pipelines on one hand and continuing to use Canadian National Railway (CN) exclusively on the other hand, or other documentation used by Union Carbide in order to come to the conclusion that there was a need for the pipelines,

(b) materials in the possession of Union Carbide regarding the lack of competitive rates as between CN and CP along with details of negotiations which took place between Union Carbide and CN, and

(c) documentation pertinent to the planning for the pipelines which would indicate relevant dates for various stages of planning.

On 8 February 1983, Union Carbide responded in writing by advising that the information relating to economic analysis and railway rates was confidential information which Union Carbide was not prepared to release, and that Union Carbide believed that it had provided all information relevant to the application to the Board.

At the hearing, counsel for the Hollands argued that the Board must have the information that was requested in the letter of 2 February 1983 in order to assess the need that Union Carbide alleged in its application, and should then adjourn the hearing to allow consideration of that information.

The Board was referred to Section 2 of the Pipeline Regulations which provides in part:

> "2(1) Unless otherwise directed by the Board, an application under Part 4 of the Act for a permit to construct a pipeline other than a flow line shall include
>
> (a) a statement indicating the necessity and purpose of the proposed pipeline"

Union Carbide responded by saying that it had put before the Board a complete application. It submitted that the information requested was not normally required by the Board in applications of this nature, that the information was commercially sensitive, and that the Board should not require Union Carbide to reveal information relating to competitive railway rates which would have the effect of damaging its bargaining position. Union Carbide pointed out that final contracts with the railway had not yet been signed and that, if it were forced to reveal its cost-benefit analysis and the information on which it was based, that would harm its present and future bargaining position with the railways. Union Carbide proposed that its witnesses could speak in a general way to the information requested.

Counsel for CP advised the Board that the revealing of any information with respect to competitive freight rates would be in breach of an American Statute, the Staggers Act, which applied to CP.

Following submissions on the motion, the Board deferred its decision until the evidence of Union Carbide had been heard and subjected to cross-examination. The Board indicated it would then assess the information before it, bearing in mind the information requested on behalf of the Hollands, and decide whether there was sufficient evidence to enable it to make a decision.

Later in the hearing, and following direct examination and cross-examination of the Union Carbide witnesses, the Board ruled that it had sufficient information to assess the application and accordingly, would not compel Union Carbide to produce additional information.

### 2.3 Jurisdiction of the Board Respecting the Rail Car Loading Terminal

The Board recognizes that, insofar as the terminal itself is concerned, the Board has no jurisdiction regarding matters of land use or development and that those are matters which are properly within the jurisdiction of other authorities.

However, the Board believes the construction of the terminal to be an integral part of the plan to construct the proposed pipelines and, for that reason, any direct impacts arising from the terminal would relate to the construction of the pipelines over which the Board does have jurisdiction. Thus the Board believes it has a responsibility to measure the adverse impacts of the terminal on the surrounding area and on persons in the area.

## 3 ISSUES

The Board believes that the issues are:

- the purpose and necessity of the proposed pipelines,
- their routes and impacts, including any impact of the rail car loading terminal.

## 4 PURPOSE AND NECESSITY

### 4.1 Views of Union Carbide

Union Carbide stated that the applied-for pipelines would transport two grades of ethylene glycol from its plant at Prentiss to a proposed rail car loading terminal in the town of Blackfalds. It stated that the need for the pipelines arose entirely from its inability to negotiate competitive transportation rates with the CN. Minimizing the cost of product distribution is essential to maintaining the competitiveness of an Alberta-based petrochemical plant serving world markets. To ensure this objective was met, access to both major railways was essential. The proposed pipelines would provide access to the second railway, CP, in an efficient and effective manner.

The applicant stated that the proposed pipelines and terminal would cost about $10 million and $5 million, respectively. These costs would be almost entirely in addition to the cost of the Prentiss project. Some rail loading capabilities at the Prentiss plant would be needed to maintain a competitive position with the railroads after the contract with CP expired and thus the Blackfalds facilities would duplicate the somewhat reduced facilities at Prentiss to the extent of about $1 million. The applicant said that the freight rates offered by CP were low enough to justify the substantial additional expenditure, and that the payback on the investment was "fairly rapid" and better than the payback period for the Prentiss plant.

Union Carbide claimed the benefits that would accrue from the proposed pipelines and terminal included the positive impact on the Town's and County's tax base, the creation of jobs, and the local purchase of materials.

With respect to alternatives to the proposed pipelines, the applicant stated that it had examined the feasibility of trucking product from the Prentiss plant to Blackfalds, but considered the resulting heavy truck traffic in the community would be unacceptable. The alternative, of rail car loading at Prentiss with switching south of Blackfalds to provide access to both major railroads, was not feasible because CN would accept interswitching for only a very limited portion of Union Carbide's total rail traffic, resulting in unacceptable distribution costs. In response to a question at the hearing, Union Carbide expressed its understanding that there might be an appeal process through the Canadian Transport Commission (CTC) in which it could apply for an order that would allow it to use the CN line from Prentiss to move cars to an interconnection with CP.

Union Carbide concluded that, if its applications were denied, it would be necessary to refit the loading facilities at the Prentiss plant and to accept rates dictated by CN.

## 4.2 Views of the Interveners

PAL contended that Union Carbide did not provide valid reasons to support the need for the proposed pipelines, nor did it show that transportation of product by rail directly from the Prentiss plant as originally proposed was no longer appropriate or viable. In closing argument, counsel for PAL and the Hollands stated that Union Carbide had not satisfied the "very heavy onus" on it to show that the proposed pipelines were necessary, but had merely indicated that, in its own assessment, it would be preferable to have the pipelines so that it could deal on a more competitive basis with both CN and CP.

PAL submitted that rail facilities exist which connect Union Carbide's Prentiss plant site to the main Alberta CN and CP lines. It said that it

might be possible, with agreement between CN and CP, for CN to switch rail cars to CP's line at an interchange south of Blackfalds, and so provide Union Carbide with access to both rail lines. The Hollands also stated that the applicant could access the CP main line south of Blackfalds thereby eliminating the need for the pipelines.

CP indicated it could not service Union Carbide's Prentiss plant over CN's Brazeau Subdivision rail line from the Red Deer Junction, the point where CP and CN tracks interconnect. CP requested running rights from CN for the line from the Red Deer Junction to the plant, but was refused. Furthermore, CP understood that CN had refused to allow Union Carbide to interchange rail cars from CN to CP at Red Deer, except to a very limited extent, effectively preventing CP from carrying Union Carbide's product either through direct service or interchange. It said that it had not discussed directly with CN the concept of CN bringing loaded cars to the Red Deer Junction to be picked up by CP, because it saw no reason, on a commercial basis, for CN to take cars 24 kilometres only to turn them over to CP, for the long haul to Vancouver and Chicago. In addition, CP stated that a separate rail line to service the Prentiss plant would cost about $20 million, and in its opinion was not economically feasible.

With respect to any appeal process by which Union Carbide could apply for an order that would allow it to use the CN line from Prentiss to move cars to an interconnection with CP, counsel for CP advised that Section 134(5) of the Railway Act, respecting running rights, applies only if a railway first applies to the CTC to construct a branch line. If the CTC believes that the branch line should not be constructed, but that running rights should be ordered on another railway in the area, then CTC can convert the application to one of running rights. However, there is no specific provision whereby a railway company can apply for running rights on another railway.

On the matter of benefits of the proposed facilities, CP referred to its beneficial rate to Union Carbide, better turnaround times, and competitive service and access. Also, if one line happens to go out for whatever reason, Union Carbide would have an alternative means of getting its product to market.

### 4.3 Views of the Board

In looking at the necessity for a pipeline, the Board does not necessarily do so with the strict interpretation of the word "necessity" in mind. That is, in instances where a proposal for a pipeline may be the preference of the applicant but not the only means of transporting the products in question, it might be said that the pipeline is not truly "necessary". In these instances where alternatives exist, the Board believes that it must appraise the necessity of a pipeline in relative terms by comparing the public interest aspects of the particular proposed pipeline to the public interest aspects of the possible alternatives to

that pipeline. These alternatives might involve other pipelines or alternative means of transporting the product.

It thus follows that the Board, in such cases when it is assessing the purpose and necessity of a proposed pipeline, may be really measuring the "justification in the public interest" of the pipeline. This justification must be weighed against the negative impacts that the proposed line could have on individuals or upon the broad public interest.

In the subject case, the Board notes Union Carbide's evidence that the need for the proposed pipelines arises entirely out of its inability to negotiate competitive transportation rates with CN. Union Carbide stated that the differential between CP and CN rates would pay back the substantial expenditure of some $15 million for the proposed pipelines and terminal at a fairly rapid rate.

The Board does not consider that trucking product from Prentiss to Blackfalds would be a better alternative than the pipelines, and indeed agrees with Union Carbide that the resulting heavy truck traffic in the community would constitute an unacceptable public interest impact. Similarly, the Board does not consider the construction of a separate rail line at a cost of some $20 million to be a better alternative in terms of the public interest, and would expect its land use impact to be at least as great as that of buried pipelines. The Board does not see the loading of rail cars at Prentiss, with switching at Blackfalds, as a viable alternative because of Union Carbide's evidence that CN would accept interswitching for only a very limited portion of the total rail traffic, resulting in unacceptable distribution cost penalties. Having regard to CP's evidence respecting any appeal process for running rights, the Board does not agree with PAL and the Hollands that Union Carbide can obtain adequate access at a reasonable cost to the CP line using the existing CN Brazeau Subdivision line which runs through the plant site.

The only viable alternative, based on the evidence, appears to be movement of the product by CN at higher shipping costs. The Board believes it would be in the public interest that this Alberta-based petrochemical plant have the capability of shipping product to a variety of markets at the lowest available transportation cost. Accordingly, the Board believes the proposed pipelines are justified in terms of the public interest. It would be prepared to approve them if the proposed routes and impacts of the project proved acceptable. The routes and impacts of the proposed pipelines are considered in section 5 of this report, and section 6 deals with the impacts of the proposed terminal.

## 5 ROUTES AND IMPACTS OF THE PROPOSED PIPELINES

### 5.1 Views of Union Carbide

Union Carbide's applied-for pipeline route (Route D) and alternative routes (Routes A, B, and C) investigated are shown on the attached

figure. Union Carbide said that its route selection process was based on several factors including minimizing pipeline length, minimizing railroad and highway crossings, and avoiding farm residences, lakes, low-lying areas, and planned or existing subdivisions, either residential or industrial.

Of the four routes examined, Route A had the advantage of being about 3 km shorter than the others and could be parallel to or included in the plant water supply line right of way for about 5.6 km at the east end. Its disadvantages were that it had two railroad crossings while the others had none, and it would cross more land with subdivision potential near Blackfalds. In addition, this route was not acceptable to Alberta Energy and Natural Resources. Routes B, C, and D were approximately equal in length, and although longer than Route A, the easterly 3 km of them would cross land already owned by Union Carbide. Field inspection of Routes B, C, and D revealed several subdivided parcels northeast of Blackfalds as well as several potential subdivided parcels east of Blackfalds. Union Carbide concluded that Route D was the preferred route because it had no railroad crossings and crossed the minimum amount of subdivided land, thus causing the least inconvenience to the landowners.

Union Carbide stated that contacts with the landowners to obtain permission to survey, and subsequent detailed soil sampling and route analysis, resulted in some minor route adjustments affecting only the original landowners. It advised that all of the landowners involved had signed an "Agreement to Route" document which included a clause that states that the property owner had no objection to the applications or the approval of them by the Board. Union Carbide stated that it understood Mr. Johnstone to believe that any objections he had could be worked out and that it was prepared to discuss with him re-routing the lines to accommodate his needs regarding subdivision. If permits were issued, Union Carbide would agree to a condition respecting the routing of the lines being acceptable to both it and Mr. Johnstone.

With respect to the impacts of the pipeline construction, Union Carbide said that to minimize potential impacts it would take appropriate action including topsoil stripping, separate storage of topsoil and spoil to prevent mixing, erosion control measures, and timing of construction. With construction scheduled for late September and early October 1983 for that portion of the route east of Blackfalds Lake, it anticipated that there would be a minimal impact on the 1983 harvest. There would be a minimal impact on agricultural operations west of the lake because there is only a small amount of cultivated land. Union Carbide said it believed that, with its proposed reclamation program, there would be minimal, if any, long-term impact. The pipelines would be installed by an experienced pipeline contractor whose work would be monitored by a full-time Union Carbide construction and environmental inspector who would ensure liaison with the local Alberta Environment representative.

Union Carbide said that, although construction procedures would make pipeline leaks extremely unlikely, it had developed operating procedures

to ensure that any leakage that might occur would be quickly detected. It said that its procedures would allow the detection of a leak as small as about 40 litres over a 30-minute period, and that its operators could then shut off the faulty line. In the presence of clean water and oxygen the product would be fully biodegradable over a period of weeks. Nevertheless, saturated soil around any pipeline leak would be removed.

## 5.2 Views of the Interveners

PAL said that it was opposed to the intrusion of any further or unnecessary developments on prime agricultural land. It said that Union Carbide had given no attention to the further impacts on the agricultural community, and appeared to have given little consideration to environmental impacts in choosing to construct the pipelines for the transport of its products instead of using the existing rail lines. It said Union Carbide paid inadequate attention to potential erosion problems and provided little or no information with respect to alternative routes. PAL stated that the overall impact of Union Carbide's proposal on the agricultural community, apart from compensation for surface right of way access, is negative. Hardly a quarter section is left that has no encumberance, be it power lines, pipelines, or other intrusions. Every new encumberance imposes restraints on future planning and development and reduces the continued viability of the farm operation. Pipelines reduce farmers' ability to drain land, fill in sloughs, deep plow, and otherwise improve the efficiency of agriculture. PAL said that erosion and settling along pipeline routes is a continuing problem and that separating soil zones and replacing them in late fall would be a problem. Although it did not suggest alternative routes, it said that Route A would be the shortest and would disturb the least agricultural land.

The Hollands stated that construction of the pipelines and termination of them at the proposed terminal would have a serious and detrimental effect to the use, value, and enjoyment of their property.

The Chamber stated that the pipelines would affect rural residents in that some agricultural land may be taken out of production and the construction phase might cause some inconvenience. The pipelines would help promote growth in Blackfalds, and if the lines were not built, there would be further industrial growth in the rural area which already has a major share of industrial development. It said that the proposed pipelines were of major importance in that the economy of Blackfalds would become more stable through a broader tax base resulting from the terminal. In the Chamber's opinion the pipelines would benefit not only the rural residents but also the people of the Town.

In his written intervention, Mr. Johnstone indicated he was applying to subdivide a parcel of land on the applied-for route, and that the proposed pipelines may affect his application. At the hearing, he

advised that he was resuming negotiations with Union Carbide, and had provided it with two alternative routes. He said that he and Union Carbide were trying to determine a route through his land which would be compatible with his subdivision plans.

## 5.3 Views of the Board

In considering the acceptability of the applied-for route, the Board has placed considerable weight on Union Carbide's evidence that all landowners along the route have no objection to the applications. In the case of the routing on Mr. Johnstone's property, the Board notes his comments that he and Union Carbide are attempting to determine satisfactory routing through his land. In any permits issued, the Board would require that Union Carbide satisfy it that the route was acceptable to both Union Carbide and Mr. Johnstone and also advise the Board of the details of the amended route.

The Board is satisfied with the technical aspects of the lines and that the pipelines could be constructed and operated as proposed by Union Carbide with only limited and acceptable environmental impacts. These would include agricultural concerns such as soil reclamation, erosion control, and settling. Having regard to Union Carbide's proposal to bury the lines at a depth of 2.5 metres, deep plowing would not be constrained.

In summary, the Board is satisfied that the proposed routing is generally satisfactory and that the negative impacts of the pipelines would be minor and acceptable. Accordingly, it would be prepared to issue the applied-for permits if the impact of the proposed rail car loading terminal was found to be acceptable.

# 6 IMPACT OF THE RAIL CAR LOADING TERMINAL

## 6.1 Views of Union Carbide

Union Carbide stated that the proposed terminal would include facilities for the heating, storage, blending, measurement, and rail car loading of the glycol product. The storage tanks would be encircled by plastic-lined dikes and the terminal would be manned during transfer and rail car loading operations. The site would require natural gas service for heating and liquid nitrogen storage for glycol storage tank padding. Truck traffic at the site would be limited to occasional diesel fuel and liquid nitrogen delivery, and maintenance vehicles.

Union Carbide stated that it did not actively investigate alternative sites but selected the proposed terminal site on the basis that it was located on CP's main line, it was for sale at the time, it was compatible

with the Town's municipal plan, and it was a site on which the Town council strongly encouraged Union Carbide to locate the terminal.

With respect to the question of noise from the terminal, Union Carbide submitted a report which dealt with the existing noise levels of the area, the acoustical characteristics of the proposed development, and the potential impact on adjacent properties. It made recommendations on methods of minimizing the potential impact. The report indicated that the people living in the area are already used to the existing noise due to road and rail movements and that the noise can be considered acceptable for a community close to high-density population areas.

Union Carbide said that noise levels emitted by additional operations on the tracks and marshalling yard will have similar characteristics to the existing noise from the passage of trains and sounding of horns. It stated that the only time when loading operations and the shunting of cars would take place on a 24-hour basis was when a unit train was being loaded. This would occur for about 3 days once every two weeks.

Union Carbide stated that it would need more tank cars if there were a prohibition against rail car shunting during the night, because lengthening the loading period would result in making fewer trips per year.

Union Carbide concluded that during rail car shunting operations at the proposed terminal, noise levels at the mobile home park would be 36-39 dBA, or at least 10 dBA below existing daytime peak levels and masked completely by present levels. Nighttime levels attributable to loading would be only 2-3 dBA less than existing levels, requiring mitigative measures which should be designed to reduce the levels by 6-10 dBA at the residential areas within the trailer park. Union Carbide stated that rail car switching, the concentrated area of car impacts, the short-haul CP engine, and other activities at the loading facility would be subjectively noticeable at the mobile home park, but are not expected to cause any adverse response because of their intermittent and short duration characteristics.

The noise report recommended, and Union Carbide proposed to install, a properly designed earth berm, with a dense planting of trees on the south end of the terminal site beside the mobile home park. The berm would be 250 metres long and have an average height of 5 metres. The report stated that the berm and landscaping are adequate to provide sufficient noise reduction to enable the intended operations to take place at the terminal during the day or night without causing any noticeable noise intrusion to residents in the mobile home park. One of the principal features of the berm is its ability to reduce peak noise levels associated with intermittent nighttime activities to levels that result in little, if any, intrusion.

Union Carbide said its confidence level was fairly high that the berm would accomplish what it was designed to do. It indicated, however, that it was prepared to commit to further action if the berm did not perform according to the calculations of noise reduction which should result. It said that it would be prepared to perform appropriate baseline noise studies prior to construction of any pipeline or terminal facilities and to make them available to the public. It would also take noise level measurements after the berm was put in place to determine its degree of effectiveness. It said that, if the noise impact of the terminal in contrast with background noise was not correctable by berming or landscaping, it might be possible to restrict terminal operations during a set of nighttime core hours to remedy the problem. However, it was confident that it would not need to restrict movements.

## 6.2 Views of the Interveners

The Hollands stated that the Blackfalds Mobile Park consisted of about 12-13 acres (5 hectares) and comprised 85 sites involving about 250 people. The park has existed on the site for about 27 years. They said that the park was bounded by Highway 2A on the east, the CP main line on the west, a town street on the south, and a vacant site to the north proposed for the rail car loading facility. The Hollands asked that the pipeline applications be refused or, in the alternative, that the termination point of the pipelines in the town be located west of the proposed site. As a further alternative, they suggested that the pipelines should have a termination point on a more suitable location in the County of Red Deer. In their opinion, marshalling yards and loading, with round-the-clock loading of cars, marketing terminals are not properly located adjacent to residential areas. They claimed the County of Red Deer and the Town have other available locations more suitable for the termination of the pipelines and in which industrial zoning is in place.

The Hollands said that the movement of pressurized containers may pose a hazard to the occupants of the mobile home park. The truck loading and unloading facilities which would form part of the marketing terminal may accommodate numerous semi-trailer movements per day. Heavy truck and railway movements adjacent to residential land cause severe disruption and are environmentally unsound.

In response to questions at the hearing, the Hollands indicated that Highway 2A adjacent to the park on the east was a busy highway but that the town street south of the park was more noisy. They said that "quite a few" trains passed the park on the CP main line regularly day and night but that once the locomotives pass by, the cars are less noisy. They referred to previous problems with "ground or earth tremor" and vibration from the trains, but indicated that substantial improvement in the noise and vibration situation had resulted from the installation of continuous track.

PAL said it was concerned about the potential impact on the residents of the Town from the noise of shunting railroad cars in the proposed marshalling yard and supported the Hollands' intervention in that regard.

The Town advised that it had adopted a general municipal plan in 1980, the objective of which was to provide long- and short-term planning strategies to maintain and improve the quality of the physical environment within and adjacent to the Town. It said that in the period 1980-1985 the Town would attempt to increase the amount of non-residential development so that it comprises not less than 25 per cent of the Town's total tax assessment. Presently, 82 per cent of the Town's tax assessment comes from residential development.

The Town advised that the present zoning of the parcel intended for the proposed terminal is "Reserved for Future Development" (RD). It further advised that it held public hearings in August 1982 to amend the general plan and the zoning by-laws to "industrial" but that no representations were made at the hearings other than by the applicant and the Town's planning consultant. Subsequently, Town council gave first and second reading to the by-law amendments. It said that it was Town policy to withhold third and final reading until a development agreement had been made between the developer and the council. Preliminary discussions regarding a development agreement have taken place and further negotiations will be undertaken once the Board renders its decision.

The Town advised that its major concern related to landscaping and berming of the site, to mitigate noise impact on neighbouring residences. It noted that Union Carbide had completed a noise study and that its discussions on the report with staff of Alberta Environment indicated that Union Carbide had adequately addressed the concern.

In summary, the Town stated that Union Carbide's proposal met major objectives of the Town in adding a new and valuable industry which it projected would improve the Town's non-residential tax assessment by some 7-8 per cent, and that Union Carbide had made a serious commitment to address environmental factors associated with the proposed development.

The Chamber stated that the proposed pipelines are of major importance in that the economy of the Town of Blackfalds will become more stable through a broader tax base resulting from the proposed terminal. It said that if the terminal were built near the Prentiss plant, more agricultural land would be lost to industry, and the construction of additional tracks and services would cause inconveniences to rural residents. In addition, the rural municipality would broaden its tax base at the expense of the Town which has land available for the terminal.

## 6.3 Views of the Board

Of the potential impacts of the proposed terminal, the Board regards noise impact as the most significant. With respect to the use of agricultural land, the Board notes that the Town is seeking to locate an industrial operation on the site to broaden its tax base and, if the proposed terminal is not located there, the site will be put to some other non-agricultural use. In this regard, the Board believes that the proposed facilities would have a modest but positive economic impact on the Town and the County in terms of taxes. Similarly, the Board believes that any economic impact from local expenditures or hiring would be modestly positive.

With regard to safety, the Board believes that the terminal can be operated safely and without any risk to the environment or local population provided that the design, construction, and operation commitments made by Union Carbide are carried out.

With respect to the matter of noise impacts, the Board believes that the measures proposed by Union Carbide, that is, the construction of the noise-reducing berm and the landscaping, will eliminate any noticeable noise impact at the mobile home park. The Board has been influenced in this regard by Union Carbide's willingness to undertake baseline noise studies prior to construction, follow-up studies during operation of the terminal with the berm in place, and to take further action, including restricting nighttime operations at the terminal, if problems remain.

The Board notes the matter of noise impact mitigation may also be addressed by the Town of Blackfalds in by-laws or through the development agreement which is being prepared.

In summary, the Board is satisfied that the impacts of the proposed terminal would be small and acceptable.

# 7 DECISION

Having regard to its conclusions that the proposed pipelines are necessary, that the proposed route of the pipelines is generally satisfactory, and that the impacts of the pipelines and rail car loading terminal would be acceptable, the Board is prepared to issue the requested pipeline permits subject to the approval of Minister of the Environment respecting environmental matters. The Board will require that Union Carbide conduct appropriate baseline and follow-up noise level surveys and provide an assessment of the effectiveness of the berm.

The Board will also require that Union Carbide satisfy it that agreement has been reached between Union Carbide and Mr. Johnstone respecting new routing on his property, and provide details of the new routing.

DATED at Calgary, Alberta, on 22 March 1983.

G. J. DeSorcy

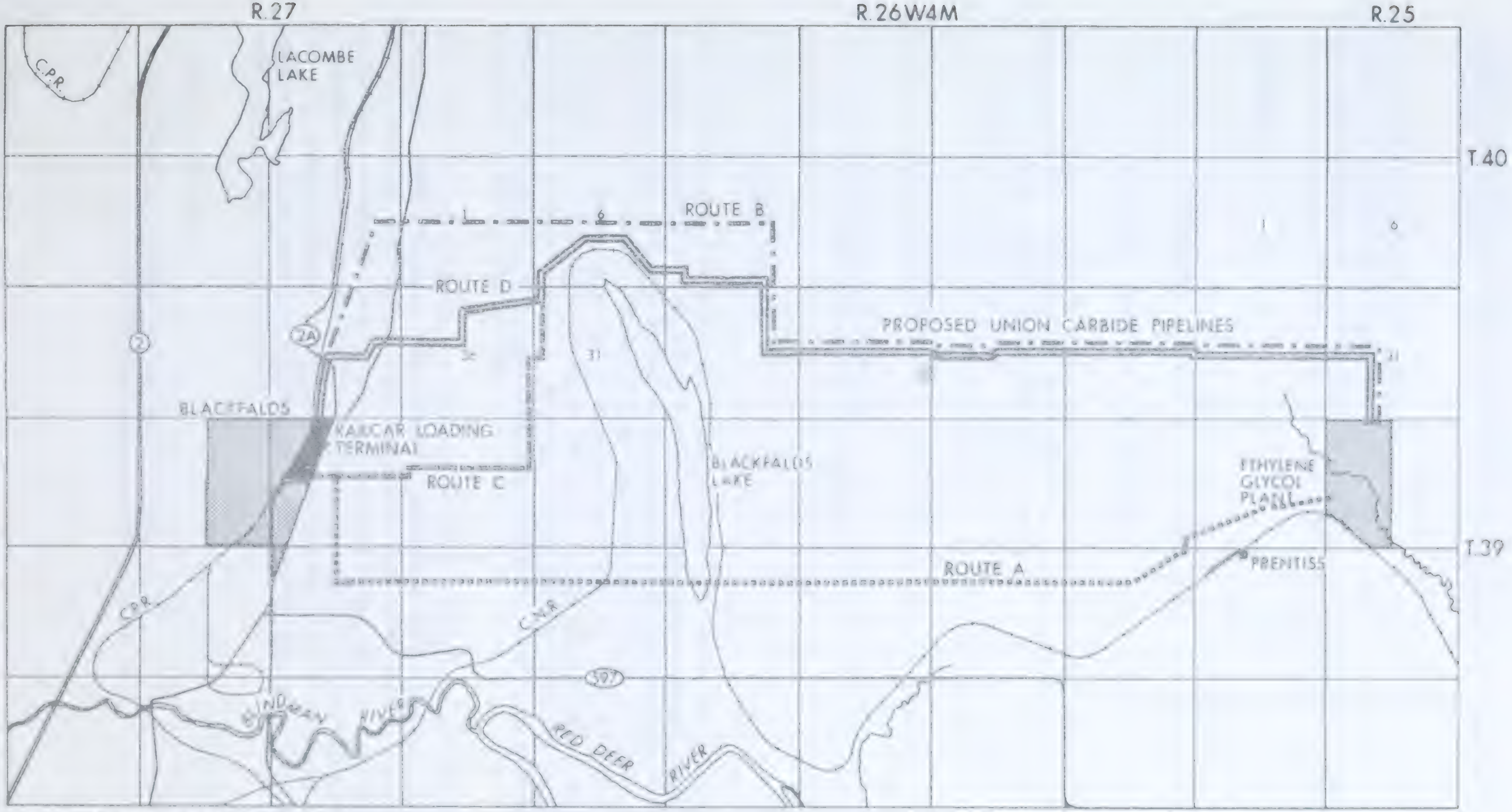
G. J. DeSorcy, P.Eng.
Vice Chairman

V. E. Bohme

V. E. Bohme, P.Eng.
Board Member

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member




UNION CARBIDE CANADA LTD
APPLICATIONS NO 820934 & 820935
BLACKFALDS-PRENTISS AREA

FIGURE TO DECISION D 83-3

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA CANADA

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

1982 ADMINISTRATION FEE APPEALS
REVIEW OF PROPOSED REVISIONS TO
THE ADMINISTRATION FEE SYSTEM

Decision D 83-4

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# 1 INTRODUCTION

The oil and gas industry in Alberta has, for many years, been required to fund, through a tax on oil and gas reserves, 50 per cent of the net estimated oil and gas related expenditure of the Energy Resources Conservation Board. The Oil and Gas Conservation Act (the Act) and the Regulations thereunder were amended in 1982[1] to provide for the levy of an administration fee on wells and oil sands projects in order to satisfy this requirement. The fee replaces the tax levied previously under a procedure of assessment and taxation that was extremely complex and difficult to administer.

This report, in section 2, summarizes the appeals made regarding the 1982 fee, and includes the Board's decision with respect to each appeal. Since 1982 was the first year in which this new system was applied, the Board has reviewed it in some detail and sets out in section 3, certain proposed modifications to it. Since no appeals were received respecting the oil sands project portion of the new system, the Board is not making changes to that portion, other than as may be necessary to reflect increased Board expenditures.

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1 Oil and Gas Conservation Act - Part 11.
Oil and Gas Conservation Regulations - Part 16.

## 2 APPEALS, HEARING AND DECISIONS

### 2.1 Notice of Levy

The Notices of Administration Fee were mailed on 16 August 1982 to 403 operators. Deadline for submission of appeals was 14 September 1982 and final date for payment was set at 15 October 1982.

### 2.2 Summary of Appeals

Twenty-six appeals were filed with the Board, eight of which were subsequently withdrawn prior to the appeal hearing. The remaining eighteen appeals were heard on 1 December 1982, by an Appeal Board of G. J. DeSorcy P.Eng., V. E. Bohme, P.Eng., and C. J. Goodman, P.Eng.

The appeals considered were placed in two groups. The first group consisted of appeals which were made pursuant to and on grounds set out in section 51(1) of the Act, and are discussed in section 2.3. The second group consisted of appeals on grounds not specified in section 51(1), including the applicability and suitability of the Act or Regulations as amended. These are discussed in section 2.4.

### 2.3 Appeals Respecting Errors in Fee Levy

The seven appeals in this group were made under section 51(1)(a) and (b) of the Act, and on the grounds that either the wrong operator was charged the fee or an incorrect fee was charged. For each appeal, the appellant, the Board staff and any other interested parties agreed that an error had been made. Provision exists in the legislation for the correction of a notice given in error or for an incorrect fee without following the appeal procedures[2]. Although each of these appeals could have been resolved through this provision, it was decided that they should be processed through the appeal procedure in this first year. A brief description of each of the appeals follows.

2.3.1 Caribe Petroleums Inc. contended that it was not the operator of two wells on the prescribed date, and that the operator on that date was Conrad Resources Ltd. Prior to the hearing, Conrad Resources Ltd. confirmed in writing that it was the operator and would accept responsibility for the administration fees.

Appeal Board Decision: Conrad Resources Ltd. is liable for the fees.

2.3.2 Chevron Standard Limited submitted a two-part appeal. Firstly, it contended that it was not the operator of two appealed wells on the prescribed date. The licensees of the wells, Petro-Canada Exploration Inc. and Ranchmen's Resources (1976) Ltd., confirmed that

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2 Section 50(5) of the Act.

Chevron Standard Limited was no longer the operator of the wells, and in fact the wells had been inactive for a number of years.

Appeal Board Decision: In that the licensees agreed with the appellant, the Board directs that the liability be transferred to them.

The second part of the appeal concerned two service wells which the appellant indicated were part of an oil sands project. When investigation revealed these wells were outside the approval area of the project, the appellant withdrew this portion of the appeal.

2.3.3. Leddy Exploration Limited contended that production of 1332.9 cubic metres ($m^3$) attributed to one of its wells was too high. The Board staff confirmed that a portion of the administration fee production had been assessed in previous years.

Appeal Board Decision: The Board approves a change in the well classification from 4 to 3, resulting in a reduction of the administration fee.

2.3.4 Many Islands Pipelines (Canada) Limited contended that the administration fee production attributed to one of its wells should have been 1167.6 $m^3$ rather than 1216.6 $m^3$. Board staff confirmed they had applied a production adjustment of 49.0 $m^3$ to this well when it should have been applied to a different well on the same legal subdivision. Correction of this processing error would alter the classification of the appealed well, but not the other well.

Appeal Board Decision: The Board approves a change in the well classification of the appealed well from 4 to 3 resulting in a reduction of the adminstration fee.

2.3.5 Petro-Can Oil & Gas Corporation Ltd. contended that it did not operate the experimental wells in heavy oil Approval No. 2768. Petro-Canada Exploration Inc. confirmed by letter it was the operator and would pay the administration fees.

Appeal Board Decision: Petro-Canada Exploration Inc. is liable for the fees.

2.3.6 Procor Limited contended that it was the operator of two water disposal wells rather than one as indicated on the Notice of Administration Fee and requested that the Board issue an amended notice. Board staff confirmed that disposal volumes were in fact delivered to two wells.

Appeal Board Decision: The Board grants the appeal and directs that an amended notice be forwarded to the appellant.

2.3.7 Turbo Resources Limited contended that it did not operate nine service wells identified in its Notice of Administration Fee. Page Petroleum Limited confirmed by letter prior to the hearing it was the

operator of the appealed wells, but that five of the nine wells were abandoned prior to 31 December 1981. Prior to the hearing, Board staff confirmed that in fact the five wells had been abandoned prior to 31 December 1981 and should therefore be exempted.

Appeal Board Decision: The Board rules that Page Petroleum Limited is liable for the administration fees related to the four capable wells and that no administration fee be levied for the five abandoned wells.

2.4 Discretionary Appeals

The Board received a number of appeals on grounds other than those set out in section 51(1)(a) or (b) of the Act. The Board has a discretion pursuant to Regulation 16.090(2), to hear an appeal on any ground the Board considers proper. As this was the first year of operation of the new levy system, the Board decided to be liberal in the exercise of this discretion. As a result, the Board heard appeals from operators arguing for a different interpretation or application of the Regulations than that relied upon by the Board, and appeals from operators of shallow gas wells who questioned the fairness of the new system in general, as it applied to them. In future years, as the initial problems with the system are corrected, the Board would not be expected to hear as many similiar discretionary appeals.

In this group there were eleven appeals dealing with four matters: the treatment of segregated wells, the application of the fee to inactive service wells, the validity of the Regulations under which the administration fee was charged, and the effect of the new system on the operators of shallow gas wells.

2.4.1 Dynex Petroleum Ltd. contended that wells using the same wellbore to report segregated production from two or more zones should be classified as one well for administration fee purposes, and the administration fee production should be the sum of the production from all producing zones. The appellant specified 16 locations in its original appeal, each of which had two well identifiers on the Notice of Administration Fee. Appeals were withdrawn on four of the locations when investigation revealed that these locations were in fact separate wellbores.

The appellant indicated that segregation was required in some cases for royalty or other considerations, and in other cases segregation was required by an order of the Board for control well purposes.

Appeal Board Decision: For purposes of Part 11 of the Act and Part 16 of the Regulations the Board considers each zone reporting segregated production to be a well. Each zone is thus subject to an individual well levy based on the reported production for that zone. Where the production is reported on a commingled basis, only one levy should be made but the class would reflect total production. The Board does recognize that certain wells are segregated for "control purposes" only, as a result of direction from the Board. In these instances, because

the segregated production is reported for the purposes of the Board, it is prepared to modify its approach so as not to charge a fee higher than would result if segregation was not occurring. For control wells designated in a commingling order issued by the Board, the administration fee payable is the lesser of:

(a) the aggregate of the fees charged for each zone as determined in the normal manner, or

(b) the fee which would be levied had the zones been commingled and production reported as one volume.

The appeal of Dynex Petroleum Ltd. is granted with respect to the segregated control wells, but the remainder is denied.

2.4.2 Three operators, Barons Oil Limited, Chevron Standard Limited and Ranchmen's Resources (1976) Ltd. contended that service wells which are inactive should not be levied an administration fee and that they should be treated in the same manner as capable oil or gas wells which did not produce in the base year.

Appeal Board Decision: The Board does not believe that a fee should be levied on inactive service wells, and therefore is prepared to amend the Notices of Administration Fee for the appellants provided that the following criteria are met:

(a) the service well was inactive during the base year, and

(b) the service well is categorized as a suspended well according to Board records on the last day of the base year.

The appeal by Barons Oil Limited respecting two service wells is granted and the fees are waived.

Chevron Standard Limited appealed 29 inactive service wells and the appeal is denied for 18 wells which do not meet the criteria set out above. The appeal is granted respecting the remaining 11 wells and those fees are waived.

Ranchmen's Resources (1976) Ltd. appealed one inactive service well which satisfied the criteria for exemption and the appeal is granted.

2.4.3 Goodyear Gas Well No. 5-130 Limited submitted a written appeal contending that:

(1) The purported Regulations under which the administration fee is charged have no standing.

(2) The assessment and classification of the appellant's gas well is erroneous.

(3) The appellant's gas well is not subject to the Regulations.

No representative of the company was in attendance at the appeal hearing.

Appeal Board Decision: The Board denies the appeal of Goodyear Gas Well No. 5-130 Limited. The fee payable by the appellant was determined correctly in accordance with the Act and Regulations.

2.4.4 Six operators, Alberta Energy Company Ltd., Aries Resources Ltd., the City of Medicine Hat, Merland Explorations Limited, Novalta Resources Ltd., and Ocelot Industries Ltd., all operate wells in shallow gas areas. These operators appealed on the basis that the fees charged to them were too high and would result in shallow gas well operators paying a disproportionately high share of the total well administration fees. In each case the appellants noted the substantial increase in the administration fee over the 1981 tax levied under the former legislation. It was the general view of the appellants that the fee schedule should be revised to use a sliding scale based on production rather than being so heavily weighted by the number of wells operated. It was also suggested that a greater number of classes of wells be established.

The 1982/83 levy was calculated according to the revisions to Part 11 of the Act and Part 16 of the Regulations thereunder. The Board is of the view that a fee properly determined in accordance with the Act and Regulations and sent to the proper party within the prescribed time cannot be varied without ignoring the statutory provisions. As a result, the appeals in this section are all denied. However, the Board wishes to make clear it has carefully studied the evidence presented and arguments made by the various appellants to support their view that the new system operates in a manner that is unfair to them. As a result, in section 3 of this report, the Board discusses the matters of concern to the appellants and raises the possibility that changes to the Regulatons may be made in the future to reduce the impact of the system on the appellants and other operators in the same position. Section 3 of this report does not form a part of the Board's reasons for decision on the appeals.

2.4.5 Alberta Energy Company Ltd. appealed on the grounds that the administration fee imposed was unfairly high and the company would bear a disproportionate share of the total administration fees the Board will receive from industry. Specific reasons given to support this appeal are set out below with the Board's comments following each item.

(a) The administration fee levy in 1982 exceeded the 1981 tax by a much higher proportion than the increase in gas production over the same period.

Board Comment: The Board acknowledges that such increases occurred in certain cases, but observes they are the result of a change in procedures that moves the distribution of the Board revenue requirement from an assessment and taxation of properties that was heavily weighted by reserves, production rates and revenue, to a well administration fee per operator that is primarily based on the number of wells operated.

(b) The rates used resulted in a fee structure that caused inequity to shallow gas well producers compared to the tax previously levied. Reference was made to a proposed fee schedule that would have, in the appellant's view, substantially reduced the fee if it had been adopted.

Board Comment: The fee structure referred to was an earlier example prepared by Board staff for a meeting with industry representatives and which attempted to indicate, for a representative group of operators, what the fee load would have been in 1979. The Board modified the then proposed structure to provide what was considered to be additional relief to shallow gas producers in the final schedule adopted by adding the class which pays no well fee.

(c) The fee schedule was set at arbitrary production levels with no rational basis, particularly for the fee cut-off between class 2 and class 3 well categories.

Board Comment: The production maximums for class 2 and class 3 wells were devised to meet general industry requests for special consideration to operators in shallow gas areas. The classes were intended to distinguish between wells in the marginal economic range and those with low but viable economics.

(d) The administration fee on its experimental wells is too onerous since these wells are not commercial.

Board Comment: Experimental wells are not exempt from a fee. Those in question were charged the same administration fee as were all other experimental wells that produced in 1982. The wells were designated as either class 3 or class 4 based on production volumes, and a fee was set accordingly.

(e) The company's share of the administration fee is significantly higher than the company's share of production and, consequently, high-productivity wells in the province are bearing a significantly lesser burden of

the administration fee than are the low-productivity wells.

Board Comment: The question of the fairness of the distribution of the administration fee is a subjective one, but it should be noted that 57 per cent of the total wells were in classes 2 and 3 and contributed 19 per cent of the total fees while the 33 per cent of productive wells in class 4 contributed 79 per cent of the total fees.

Appeal Board Decision: The Board denies the appeal of Alberta Energy Company Ltd. The fee payable by the appellant was determined correctly in accordance with the Act and Regulations.

2.4.6 Aries Resources Ltd. appealed on the grounds that the substantial increase in the 1982 administration fee over the 1981 taxation was not intended in the introduction of a new method for calculating Board fees. No representative of Aries Resources Ltd. appeared at the hearing.

Appeal Board Decision: The Board denies the appeal of Aries Resources Ltd. The fee payable by the appellant was determined correctly in accordance with the Act and Regulations.

2.4.7 The City of Medicine Hat submitted an appeal on the 1982 well administration fee addressing the substantial increase over the 1981 tax and the concern that it was disproportionately high in its relation to the amount of Board staff time required with respect to the City's shallow, dry, sweet gas wells. The appeal also referred to 45 dually completed wells for which the City claimed it should pay only one fee for each well.

At the hearing, additional information was submitted that reviewed the nature of the municipal production/distribution system, the low market price in the Medicine Hat area, the number and types of wells including wells dually completed, and the effect of the limited number of classes used in the fee schedule.

Board Comments: The well administration fee procedure, unlike the previously used assessment method, does not recognize the price at which production is marketed. The different classes used in the schedule are based upon the producing rate but the number of classes were kept to a minimum for 1982. A major reason for this is because much of the Board's work is largely dependent on the number of wells rather than the producing rate or the price at which the products are marketed.

With respect to the 45 wells dually completed in the same wellbore, the special status for dually completed wells required by the Board for control purposes (granted in response to the appeal of Dynex Petroleum Ltd.) is considered to apply to this appeal.

Appeal Board Decision: Eighteen dually completed wells have been found to be control wells and the Board grants a revision of the administration fee for those wells where application of the criteria for special status would result in a revision. The Board denies the remainder of the appeal of the City of Medicine Hat. The fee payable by the appellant was determined correctly in accordance with the Act and Regulations.

2.4.8 Merland Explorations Limited agreed that the 1982 procedure is conceptually more acceptable than that used in previous years, however, it claimed the new system had shifted an undue degree of burden to the shallow gas producer.

At the hearing, the appellant suggested that Board staff meet with the industry associations and in particular some of the shallow gas operators in setting the 1983 fee schedule.

Appeal Board Decision: The Board denies the appeal of Merland Explorations Limited. The fee payable by the appellant was determined correctly in accordance with the Act and Regulations.

2.4.9 Novalta Resources Ltd. appealed on the grounds that the new method has been over-simplified in that it failed to recognize many of the fundamental factors which were part of the former assessment process and that producers of low-productivity gas are paying a disproportionately high share of the fee in relation to their production.

At the hearing, it added that with the new procedure, there is no period allowed to appeal the factors used in the administration fee prior to the issuance of invoices for the fee. Concern was also expressed with regard to the fact that the entire fee is now addressed to the operator rather than being apportioned to all interests including royalty-interest owners in a property as in the past.

Board Comment: The earlier comments respecting the distribution of fees, the number of classifications, and the relationship of Board costs to the number of wells, all apply with respect to this appeal. The Board recognizes that the procedure it used in 1982 did not allow for input from industry on the specific fees to be levied for each class of well.

Directing the total administration fee to the operator for payment was considered one of the principal benefits of the revised well administration fee procedure. The fee may be treated as a normal operating expense to the operator and charged out to working interest participants as is any other expense. This has resolved the long-standing problem of determining responsibility to pay and the adjustments required to establish the cost as an operating cost where a participant has made direct payment. For the Board, the savings resulting from not maintaining detailed ownership records and apportioning the fee accordingly is substantial.

Appeal Board Decision: The Board denies the appeal of Novalta Resources Ltd. The fee payable by the appellant was determined correctly in accordance with the Act and Regulations.

2.4.10 Ocelot Industries Ltd. appealed the administration fee on the grounds that shallow gas operators will bear a greater proportion of the total fee than is warranted.

Appeal Board Decision: The Board denies the appeal of Ocelot Industries Ltd. The fee payable by the appellant was determined correctly in accordance with the Act and Regulations.

## 3 WELL ADMINISTRATION FEE SYSTEM

### 3.1 The New System

The Well Administration Fee System introduced in 1982 replaced the previous assessment and taxation procedure that had been used to raise the industry portion of the Board's oil and gas related expenditure. The change was made in order to provide a simpler method of distributing the 50 per cent industry share of Board expenditures. The previous assessment procedure was complicated and costly, both with respect to administration by the Board and verification by industry of its tax liability.

The two principal features of this new system are:

1. The fee is an annual charge per well directed to the operator of the well. The fee may be considered as a well operating expense and a charge against the working interest owners of the well. The removal of a direct charge against freehold royalty-interest owners was considered desirable due to the fact that, in most instances, the charge was very small and meant a great deal of record keeping for a small amount of money.

2. The system excludes reserves or value of production from consideration in arriving at the fee to be paid as these factors have little influence on the administrative costs incurred by the Board.

The first of the features in the new system was readily endorsed by industry representatives as it suited normal industry treatment of payment and distribution to participants of well operating expenses.

It was pointed out by industry representatives that a single fixed fee per well would cause a substantial change in the allocation of the Board costs among members of the industry, particularly for those operators having large numbers of shallow gas wells with low reserves and productivity. These parties previously had been assessed and taxed at relatively lower levels. For this reason, the Board decided that a factor

should be introduced related to production to modify the impact of a single fee imposed on each producing well. The following classes of wells and fees were introduced and when applied for the 1982 year, the following distribution of generated funds resulted:

I

| Class | Definition | Well Fee | No. of Wells | % of Total Wells | Total Fee (thousands) of dollars) | % of Total Fee |
|---|---|---|---|---|---|---|
| 1 | Service Well | $ 100 | 4,331 | 10 | 433 | 2 |
| 2 | Producing Less than 400 $m^3$ | Nil | 11,475 | 27 | Nil | Nil |
| 3 | Producing 400 - 1200 $m^3$ | $ 250 | 12,512 | 30 | 3,228 | 19 |
| 4 | Producing Over 1200 $m^3$ | $1,000 | 13,597 | 33 | 13,597 | 79 |
| | | | 41,915 | 100 | 17,268 | 100 |

3.2 Revisions to the System

When it instituted the new system, the Board had planned to review it in some detail after one year's use. That fact, coupled with the number of appeals which addressed the "fairness" of the new system, has caused the Board to make a detailed review and to report that review in this document.

The Board is satisfied that the concept of the new simplified system has been generally accepted and intends to continue its use, subject to modifications which may arise as a result of this review. The system as used in future years will also recognize the decisions given earlier in this report as a result of appeals. In assessing the system and the degree to which it accomplished in 1982 the objectives the Board had in mind, the Board considers it should do so under the following general headings:

(1) The distribution among various classes of wells of the total funds raised.

(2) The number and basis for definition of classes of wells.

(3) The question of input from industry with respect to the various classes.

### 3.2.1 Distribution

Several appellants questioned the new system on the basis that operators of low-productivity wells carry too great a burden with respect to the industry's share of the Board's cost. The Board recognizes that this question of an appropriate distribution is a subjective one but notes from Table I set out earlier in this section that the so-called high-productivity wells with a producing rate of greater than 1200 $m^3$ per month make up only some one-third of the total number of wells but account for about 79 per cent of the total funds collected. This demonstrates that the Board has accepted that the fees should not be levied totally on the basis of well count even though an analysis of its expenses suggests a fairly close relationship between Board costs and the number of wells. The question of distribution thus comes down to a matter of the degree to which the Board is going to shift the responsibility for funding its expenditures to operators of wells which produce at a higher rate than the average well in the province.

The Board, on reviewing the data set out in Table I believes that in a broad sense, the existing distribution is reasonable. It does recognize, however, that the detailed distribution can be significantly altered by changing the number of well classifications. This matter is discussed in the next subsection of the report.

### 3.2.2 Number of Classifications

The Board considers the broad distribution resulting from its 1982 Fee Schedule to be generally acceptable in that it places responsibility for three-quarters or more of the industry portion of the Board's expenditures on the one-third or fewer wells which have the highest productivity. It does, however, agree with a number of appellants that there are not enough classifications to give the appropriate weight to productivity in assessing Board costs against industry. One of the outcomes of this is that a well which produces a few cubic metres of oil per year pays the same fee as one which produces 399 $m^3$ per year. Similarly and in even more extreme illustrations, a well which produces 400 $m^3$ per year generates the same fee as a 1199-$m^3$ producer, and a 1200-$m^3$ per year producer is assessed the same fee as a well which is capable of producing 15 000 or more cubic metres per year.

As stated earlier, the Board recognizes that its costs related to a high-productivity well are probably not much different than those costs associated with the average low-productivity well. Nevertheless, the Board does agree with several appellants that a greater number of classes based on productivity would result in a fairer system. With this in mind, the Board has developed a revised classification schedule

which it believes better accommodates the objectives of being relatively simple to apply, of assessing costs in a manner that is somewhat related to the degree of expenditure required by the Board and at the same time recognizes that low-productivity wells are often marginal in an economic sense. The new schedule which the Board believes would be generally more acceptable is as follows:

Table II

| | | |
|---|---|---|
| Class 1 | - | Service Wells |
| Class 2 | - | Wells producing less than 200 $m^3$ per year |
| Class 3 | - | Wells producing between 200 and 600 $m^3$ per year |
| Class 4 | - | Wells producing between 600 and 1200 $m^3$ per year |
| Class 5 | - | Wells producing between 1200 and 2000 $m^3$ per year |
| Class 6 | - | Wells producing between 2000 and 4000 $m^3$ per year |
| Class 7 | - | Wells producing between 4000 and 6000 $m^3$ per year |
| Class 8 | - | Wells producing in excess of 6000 $m^3$ per year |

The introduction of additional classes will cause some redistribution of the total well administration fee amongst operators as compared to that in 1982. It should be noted, however, that the average fee per well in 1982 was \$412. With the increased number of wells in 1983, together with the impact of substantial budget restraints by the Board for the 1983/84 fiscal year, it is not expected that this average fee per well will exceed \$400.

The classifications in Table II have been defined with oil production in mind and the regulations will spell out the appropriate conversion factor for purposes of gas wells. The Board's intent is that Class 2 wells would be exempt from any fee payment, and that Classes 3-8 wells would have a fee in the order of \$100 to \$1500 per well and would be set in a reasonably uniform step-wise manner. The actual fee structure would be announced by changes to the Regulations.

### 3.2.3 Input by Industry

One of the appellants suggested that modifications should be made so that the industry could have input as to the classes established and the fee structure. Indeed the appellant pointed out that the wording of the legislation is such that the only matters which could be appealed are

those where errors in ownership or producing rates had been made in the administration of the system. The appellant thus claimed that the appeal process was somewhat meaningless.

The Board agrees that, particularly during the early years of the use of the new system, provision should be made for industry to comment on the manner in which the classes and fees are set. The consideration being given these matters in this report is a reflection of that view. At the same time, the Board recognizes that any new system, when related to the reserves, production and value assessment approach used prior to 1982, will cause a shift in terms of the portion of the Board's expenditures being met by the various groups of producers. In those circumstances, it is unlikely that a concensus can be achieved. However, the Board does believe that an opportunity should be provided for comments from industry prior to the finalizing of the classes and the fees to be set out in the Regulations. This report is being distributed to industry to provide that opportunity and the Board is prepared to receive written comments which it will consider before it establishes the classes and fees for 1983. The Board would ask that any comments be provided to it in writing not later than 13 May 1983.

Dated at Calgary, Alberta, on 4 April 1983.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy
Vice Chairman

V. E. Bohme
Board Member

C. J. Goodman
Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary, Alberta



SYNCRUDE CANADA LTD.
OVERBURDEN DISCARD SITE

Decision D 83-5
Application 821217

# 1 INTRODUCTION

## 1.1 The Application

Syncrude Canada Ltd. submitted Application 821217 under section 31 of the Oil and Gas Conservation Act for approval to construct a permanent mine-overburden discard site in parts of sections 12, 13 and 14, Township 92, Range 11, West of the 4th Meridian at the southwest edge of the 25-year mine area (Figures 1 and 2).

## 1.2 The Hearing

The application was heard by the Energy Resources Conservation Board on 21 January and 8 and 9 February, 1983, with Messrs N. Strom, P.Eng., (Chairman), V.E. Bohme, P.Eng., and R. Paterson, P.Eng., (Acting Board Member) sitting.

The participants in the hearing, and their representatives and witnesses, are listed in Table 1.

# 2 BACKGROUND TO THE APPLICATION

In 1968 Syncrude was granted approval to produce synthetic crude oil from Bituminous Sands Lease No. 17 in the Athabasca Wabiskaw-McMurray Oil Sands Deposit. The Syncrude project, which commenced production in 1977, comprises an open-pit mine using draglines, bucket-wheel reclaimers and conveyors to transport the bituminous sands to an extraction plant where a hot-water process is used to separate bitumen from the sand. Wastes from the extraction plant are clean sand, wet tailings sludge, and tailings water, all of which are currently directed to the tailings pond. In future, mined out areas will be used for tailings sand storage. The bitumen is upgraded to synthetic crude oil using fluid coking and hydro-conversion processes. Solid by-products include sulphur, which is marketed, and coke, which is stored.

Syncrude's original mine plan was to use draglines to mine ore and to cast overburden into the mined-out portion of the pit. Operating experience has shown, however, that to optimize ore recovery and mining efficiency, it is necessary to prestrip the overburden materials using mobile equipment (hydraulic shovels, front-end loaders and trucks). The overburden material has then to be disposed of in-pit or at discard sites outside the mine area. External discard sites S1 and S2 (Figure 2) have reached their ultimate elevation and are not capable of additional storage capacity. In 1979, Syncrude applied to the Board for approval to

TABLE 1 THOSE WHO APPEARED AT THE HEARING

| Principals and Representatives (Abbreviations used in Report) | Witnesses |
|---|---|
| Syncrude Canada Ltd. (Syncrude) | G. W. Krause, P.Eng. |
| | Dr. J. R. Clement |
| V. P. Kaminsky | A. Gordon |
| R. Nilson | |
| Fort McKay Indian Band | J. Boucher |
| | I. Faichney |
| J. Brisbois | F. Orr |
| | R. Justus |
| Energy Resources Conservation Board staff | |
| D. Holgate | |
| B. D. Prasad, P.Eng. | |
| Alberta Department of the Environment | |
| L. Brocke, P.Ag | |

An intervention filed by Mr. T. P. Clarke was withdrawn prior to the hearing.

establish the S4 discard site to dispose of reject materials from its prestripping operation. The S4 site, authorized under Approval No. 2959, will reach its full capacity in 1984 and is the only permanent external discard site presently available.

## 3 THE ISSUES

The Board considers the main issues to be:

- need for an additional external overburden discard site
- scheduling of the discard site
- site selection factors
- geotechnical factors
- environmental matters
- reclamation of the site
- social impacts

# 4 NEED FOR AN ADDITIONAL EXTERNAL OVERBURDEN DISCARD SITE

## 4.1 Applicant's Views

Syncrude submitted that the need for an additional external overburden disposal site is a function of the overall program for tailings management. The tailings consists of a clean-sand phase, used to construct the perimeter dykes in the major tailings impoundment area north of the plant, and a tailings sludge phase, which is stored within the dyked area. Syncrude pointed out that, in 1986, the construction of the tailings-pond dyke will be complete and from that time onward the pond will be used as a thin-sludge and water-recycle pond. Thus, commencing in 1986, the tailings sand fraction will have to be directed to the mined-out pit in accordance with the long-range development and reclamation program. Moreover, it is necessary that the in-pit storage cells have competent foundations in order to provide maximum assurance against slumping failure of the cells as they are constructed. Thus, it would be unacceptable to place low-competency overburden material such as the Clearwater Formation clays into the in-pit foundation. These Clearwater clays will be encountered in the mining operation starting in 1984 and should be placed in out-of-pit disposal sites for the reasons outlined.

Syncrude also indicated that total external discard volumes would amount to 45 million loose cubic metres from now until 1995, at which date the proposed discard site would be full. An additional 25 million to 40 million loose cubic metres would accumulate from 1995 to 2002 and additional external discard site storage would be required for that phase of operations.

Syncrude thus contended that both an immediate and a long-range need exist for overburden disposal sites that are external to the mined-out pit.

## 4.2 Board's Views

The Board regards the question of need as being one of optimum tailings management and the achievement of reliable tailings-sand disposal cells in the mined-out pit. Achievement of the latter is necessary to assure efficient ore recovery and delivery to the plant and also to ensure a sound reclamation program for the mined area. The Board concludes that there is need for a permanent overburden discard site outside of the mine pit in order to ensure reliability of the entire material management and reclamation program.

# 5 SCHEDULING OF THE DISCARD SITE

## 5.1 Applicant's Views

Syncrude stated that its long-term mine plans show that the need for additional out-of-pit disposal capacity is immediate. Syncrude submitted a 5-year material balance plan (1983 to 1987) that showed the existing S4 site reaching capacity in 1984, and the proposed site coming into use the same year. In order for that to occur, drainage of the muskeg covering

the proposed site would have to commence during the winter of 1982-83 to allow the one-year period necessary to ensure a stable foundation.

Syncrude stated that initial overburden disposal to form the base of the proposed site would be required in 1984 to establish the ability to fully utilize the dump. If the proposed site was not available in 1984, the start-up capability of the site would be lost until 1985. Syncrude indicated that, if that were the case, rather than risk the stability of the in-pit tailings by placing more overburden in-pit, it would be preferable to reduce the prestripping lead time from the present 9 months to approximately 6 months and endeavour to make up this volume in the future.

## 5.2 Board's Views

Respecting scheduling of an additional external discard site, the Board observes that, even if the S4 site had not reached its capacity in 1984, it would be impossible to use it for development of the cells required to contain the low-competency Clearwater clays that will be mined starting in 1984.

It appears that it would be very difficult, and would require some very innovative mine scheduling, to defer mining of the Clearwater clays to 1985, this being necessary to gain a one-year additional delay in commencement of the new external discard site. While a one year delay may be possible, the Board agrees that early access to the new site, such that it could be put into use sometime in 1984, would be very desirable.

Unfortunately, other aspects of site availability and site preparation appear on the evidence to be only tentative and these may preclude access within this critical time frame. These include:

- the need for muskeg drainage
- the possible desireability of stripping and storing the muskeg for future reclamation
- the acquisition of the necessary right-of-access provisions including mineral and surface leases
- the preparation of development and reclamation plans clearly demonstrating that all suitable environment protection measures, particularly those respecting the control of potential water run-off, could be installed without serious technical problems.

The Board concludes that there is some urgency for selecting and designing of a new discard site for use by 1985, irrespective of the choice of location. However, the late submission of the application and the need for a public hearing makes it unlikely that access during the current winter season will be attained.

# 6 TECHNICAL AND ECONOMIC SITE SELECTION FACTORS

## 6.1 Applicant's Views

The applicant stated that ten alternative locations were examined for the discard site (Figure 1). The results of the evaluation, including the suitability of each site from technical, economic and environmental viewpoints, are shown in Table 2.

The sites were evaluated in accordance with the following criteria:

- Uneconomical mining zone. An area was considered uneconomic to mine if one or more of the following conditions applied: the waste-to-ore ratio was greater than 3:1, the ore grade was less than 6 mass percent bitumen, or the oilsand layer was less than 3 metres thick.

- Environmental constraints. The dump should result in minimal environmental impact.

- Haul distance. The shorter the haul distance between the overburden removal location and the discard site, the more economically desirable the dump site is.

- Interference with major surface features. The site should not interfere with or encroach upon major surface features such as corridors, roadways, or bodies of water.

- Surface preparation. The site should require as little surface preparation as possible.

The results of Syncrude's evaluation are shown in Table 2 and indicate that Site 6 is the most desirable. The applicant contended that most of the proposed site was uneconomic to mine because of waste-to-ore ratios in excess of 3:1.

The applicant stated that the proposed site was located outside Syncrude's lease boundary on land under which the oilsands are leased to Chevron Canada Limited. Syncrude planned to pursue a three-way mineral lease exchange between Chevron Canada Limited, the Crown and Syncrude after the Board's approval of the proposed site was obtained.

Syncrude pointed out that the proposed site outline (Figure 2) was defined by the following physical and geological constraints:

- Alberta Power Line right-of-way along the southern edge of the Syncrude lease.

- High-water level of the Beaver Creek Reservoir.

- The 3:1 waste-to-ore ratio contour.

## 6.2 Board's Views

The Board has reviewed the prominent features and implications of each site considered by Syncrude in selecting a suitable discard location. The Board agrees with Syncrude that Sites 9 and 10 should be rejected primarily on the basis of proximity to the plant complex and the water storage reservoir and the relatively small storage capacity. The Board also agrees that Sites 7 and 8 should be rejected because of the high cost incurred by the excessive haul distances.

The Board considers Sites 1 and 3, shown in detail on Figure 2, as being technically, economically and environmentally suitable. However, because use of these sites would cause a direct reduction in low-cost mineable ore, they should only be used if no other alternative can be found. Regarding Site 2, the Board accepts Syncrude's opinion that undesireable environmental complications and risks, as well as physical access problems, cause this to be a relatively poor option.

The Board considers Site 4 to be a viable future additional discard site although the haul distances are greater than those associated with the proposed Site 6. Similarly, the Board considers Site 5 to be a good second option in the event that Site 6 is otherwise found unacceptable or Syncrude is unable to acquire access.

The Board therefore concludes that, excluding environmental or other surface access questions, Site 6 as applied for, is the most advantageous from the viewpoint of the mine development plan, and the next best, in order, are Sites 5 and 4. All other sites investigated appear generally unacceptable.

With respect to the presence of bitumen reserves in the area of the proposed Site 6, the Board generally agrees with the 3:1 waste-to-ore ratio contour for indicating non-economic mine limits. It notes that to accurately establish the mineable bitumen reserves would require increased core-hole drilling density in the Site 6 area.

# 7 GEOTECHNICAL FACTORS

## 7.1 Applicant's Views

The applicant stated that construction of the proposed site would take place without removal of muskeg material. However, it had been unable to survey the extent of muskeg on the proposed site due to lack of access. If necessary, sand drains would be installed to drain sub-foundation material to ensure the stability of the site. Syncrude further stated that the lift thickness would be restricted to 3 to 4 metres and that the material would be track-packed to increase compaction.

Syncrude stated that storage cells approximately 125 metres wide would be constructed using competent overburden materials to form the perimeter dykes and that the less-competent materials, especially the Clearwater clays, would be placed in "slop cells" within the dykes. The Clearwater clays are thought to be difficult to recompact, have low angle of repose once disturbed, and could cause serious stability problems if used for

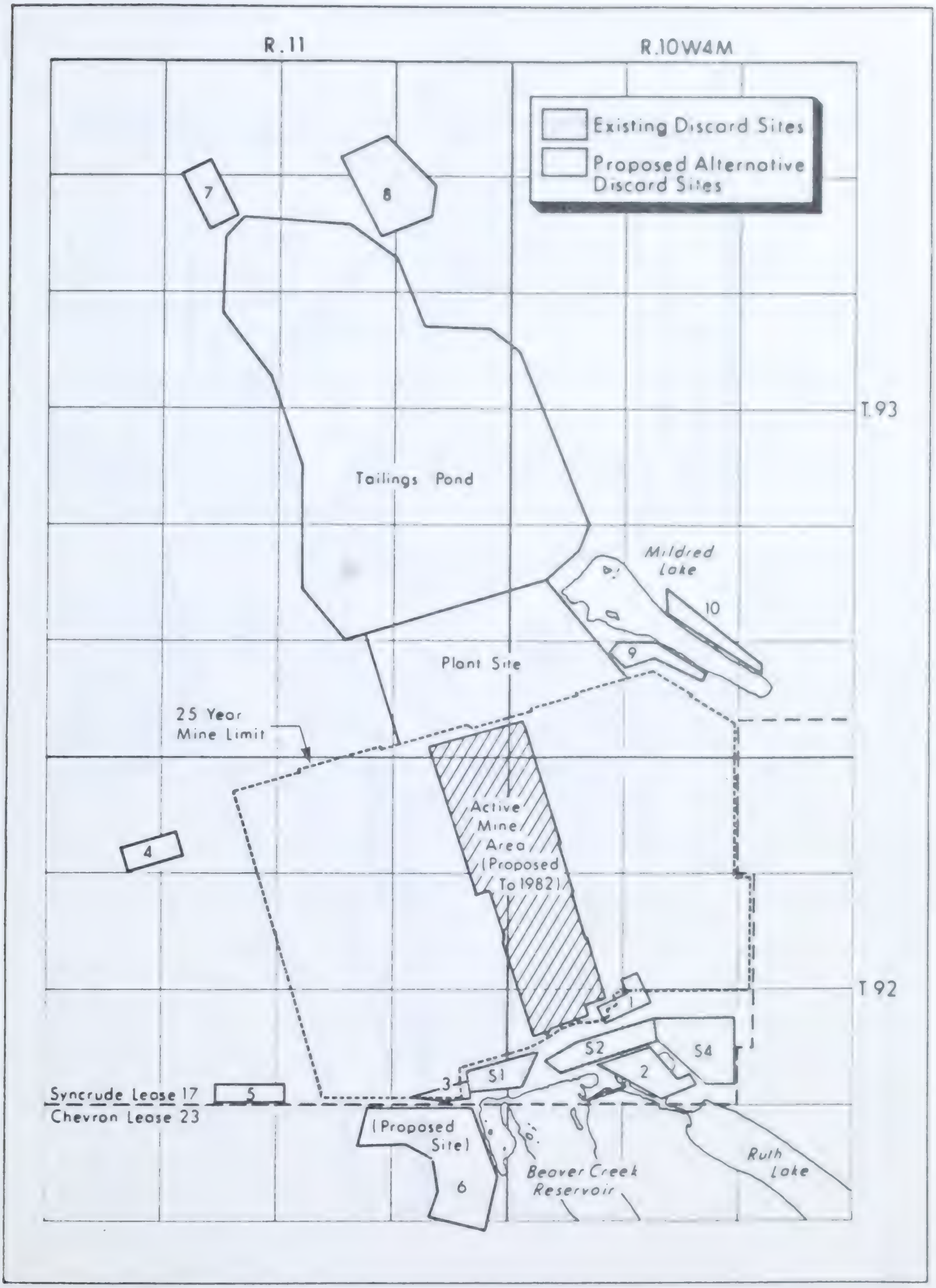



FIGURE 1 PROJECT AREA AND APPROXIMATE ALTERNATIVE DISCARD SITES

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA CANADA

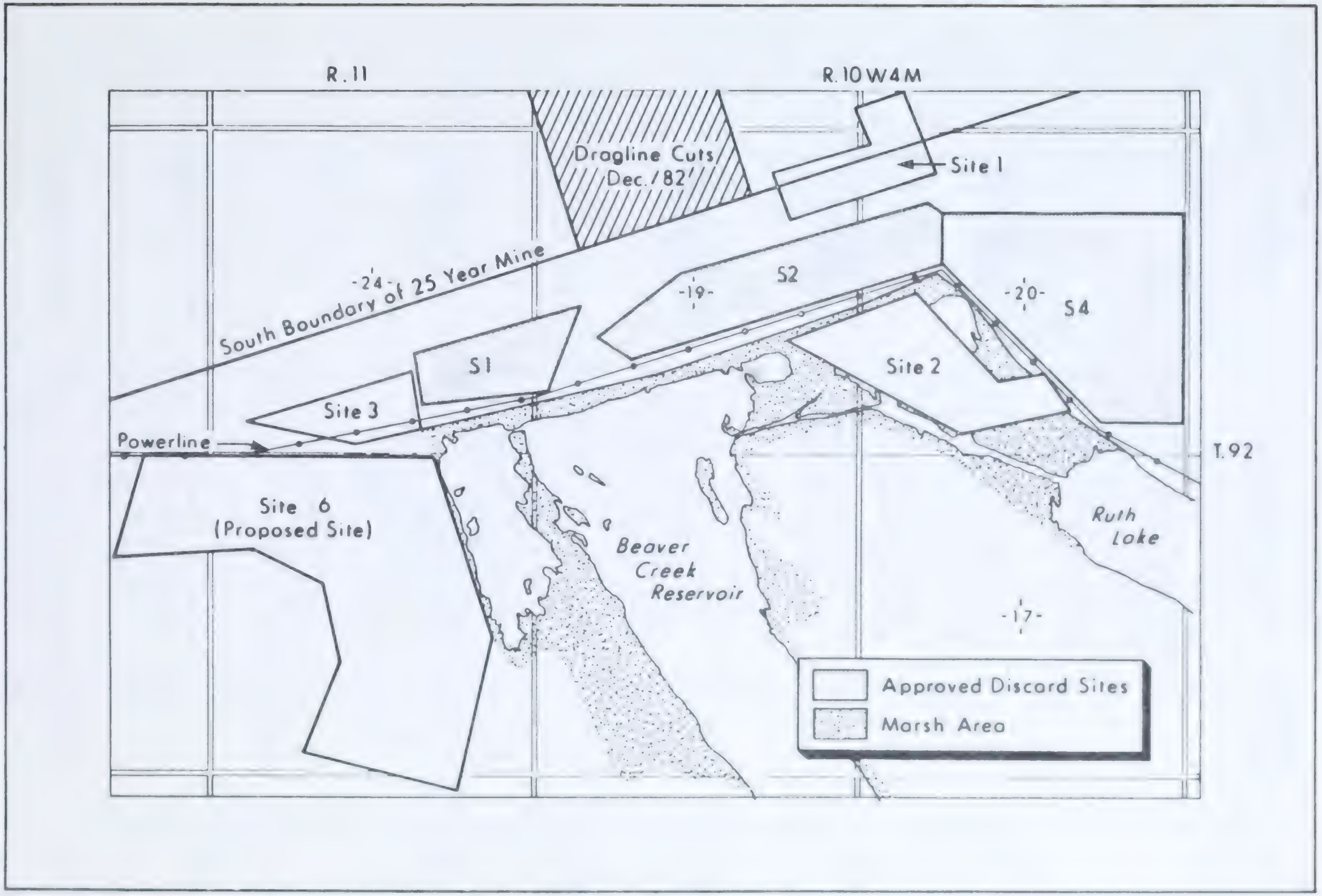



FIGURE 2 CURRENT DISCARD SITE AND PROPOSED SITE

TABLE 2: ALTERNATIVE EXTERNAL DISCARD SITE LOCATIONS SHOWN IN FIGURE I

(after applicant's submission)

| SITE NO. | LOCATION | COMMENTS/CONSIDERATIONS | INCREMENTAL HAULAGE COSTS $/BCM | EVALUATION |
|---|---|---|---|---|
| 1 | Southeast Quadrant of Base Mine, Exclusion area | o Area available not sufficient for planned volumes<br>o Relocation of 25 KV line required<br>o Limits of exclusion area are subject to change with additional geological information and changing economic factors.<br>o Located on an area uneconomical to mine, waste to ore ratio three to one. | + 0.14 | Unacceptable |
| 2 | Ruth Marsh area (extension of S-2 and S-4 dumps south) | o Located on mineable tarsand<br>o Environmental concerns<br>o Construction of containment dam<br>o Relocation of APL right of way<br>o Installment of pumping station | + 0.41 | Unacceptable |
| 3 | Extension of S-1 to the west | o Located on mineable tarsand<br>o Environmental station on site<br>o Relocation of APL right of way | - 0.18 | Unacceptable |
| 4 | High stripping ratio area North West of 25 year mine area | o Additional haul roads required<br>o Excessive haul distances<br>o Extensive surface preparation<br>o Creates mining difficulties in the future<br>o Located on an area uneconomical to mine, waste to ore ratio greater than three to one | + 1.83 | Undesirable |
| 5 | High stripping ratio area South West of 25 year mine area | o Additional haul roads required<br>o Excessive haul distances<br>o Extensive surface preparation<br>o Relocation of APL right of way<br>o Located on an area uneconomical to mine, waste to ore ratio greater than three to one. | + 1.55 | Undesirable |
| 6 | On Chevron lease (proposed S-5 dump) | o Located on an area uneconomical to mine, waste to ore ratio greater than three to one.<br>o Short haul distance for an external dump for West mine.<br>o Access under APL lines<br>o Extension of haul road required | 0 | Acceptable |
| 7 | Clay pit north of tailings area | o Excessive haul distances. This area could become desirable as the mine limits move West.<br>o Access restricted through tailings area<br>o Pit currently in use. | + 5.79 | Undesirable |
| 8 | Sand pit north of tailings area | o Excessive haul distances. This area too could become desirable as the mine limits move West<br>o Access restricted through tailings area<br>o Pit currently in use. | + 7.07 | Undesirable |
| 9 | West of Mildred Lake, east of current tank farm | o Small area<br>o Restricts future plant expansion if required<br>o Available only as a temporary dump<br>o Environmental concerns<br>o Heavy equipment would cross major access road | + 1.41 | Undesirable |
| 10 | East of Mildred Lake | o Causeway required across Mildred Lake<br>o Access under APL right of way<br>o Haul road crosses Syncrude access road<br>o Long haulage distances<br>o Relocation of R. Angus laydown area<br>o Located on recoverable granular resources<br>o Environmental concerns | + 1.28 | Undesirable |

dyke construction. The proposed design would not only result in more stable construction but would also improve the potential for reclamation of the site.

The proposed site design would provide for 6.5:1 slopes overall on the north and east walls, while the south and west walls would have 6:1 overall slopes. The maximum design height would be 50 metres resulting in a factor of safety of 1.2, the same as applied at Syncrude's existing discard sites.

## 7.2 Board's Views

Since the potential amount of muskeg present on the proposed site has not been accurately determined and the requirement for ditching and drainage has not been determined, stability analyses for the site cannot be fully defined at this time. As a result, the ultimate slope angles for the overburden storage site would probably have to be modified when more detailed information was available. The Board is also of the view that sufficient instrumentation would have to be installed and monitoring carried on to ensure that the overall slope integrity was maintained during construction.

In addition, because a slope failure would pose serious safety and environmental risks, as well as introducing long-term technical difficulties, the Board believes that careful controls on construction rates and procedures would need to be established.

# 8 ENVIRONMENTAL MATTERS

## 8.1 Applicant's Views

The applicant stated that although its application was filed under section 31 of the Oil and Gas Conservation Act, the application did not contain information regarding environmental matters because the submission followed clause 13 of Approval No. 2959 as a guideline and this clause does not specifically request environmental information. Syncrude further stated that environmental matters would be dealt with at a later date in conjunction with Alberta Environment's Development and Reclamation approval requirements.

Syncrude stated that the site selection process included a qualitative evaluation of environmental matters but that most of the sites, including the proposed Site 6, were similar environmentally and did not present serious environmental concerns. In general, only those sites immediately adjacent to open water were environmentally unacceptable for a discard site. The applicant further stated that a detailed environmental assessment of the alternative sites had not been completed and consequently a detailed comparison of the sites on an environmental basis was not available.

However, the applicant contended that Site 6 was neither unique nor critical as a wildlife habitat as similar terrain and vegetative cover is essentially continuous throughout the region. Therefore wildlife species should not be uniquely dependent on the proposed site area.

Syncrude indicated that muskeg drainage and surface water run-off would be controlled by perimeter ditches, which would channel water to the out-of-pit sump for settling and mixing with other drainage water prior to disposal in the Beaver Creek Reservoir.

### 8.2 Intervener's Views

The Fort McKay Band stated that the proposed development would result in the complete destruction of the present natural environment in Site 6 as well as the adjoining lands. The Band further contended that Mr. Orr derived a substantial portion of his hunting, trapping, fishing and gathering livelihood from this particular area and that the discard site would make the area virtually useless for these purposes. The Band noted that lands that would be affected cover an area substantially larger than the 170 hectares suggested by Syncrude and that a "small mountain would eventually result". The intervener further stated that, contrary to Syncrude's opinion, abundant wildlife did live in this area and that the discard site would cause the wildlife to migrate to other areas. In addition, natural surface-water drainage patterns would be altered and thereby affect both fish and wildlife.

### 8.3 Board's Views

The Board is of the view that detailed environmental information would have helped expedite the review process and better aided in addressing the intervener's concerns on environmental matters. On a relative basis, however, the Board is inclined to agree with Syncrude that environmental conditions are similar throughout the region and that Syncrude identified the major environmental contraints associated with each site. Also, the Board sees the proposed site as producing a relatively minor impact compared to the overall project impact. However, there is no question that wildlife would be totally displaced and discouraged from living in the site area probably throughout much of the 15 years of active use.

With respect to the water management program, the Board believes an environmentally acceptable plan is achieveable with a suitable ditching program if included in future development and reclamation plans. Also, because the area appears to be low-lying and partially muskeg-covered, the Board notes that the vegetative potential would probably be enhanced if the land surface were raised. In this respect the Board does not regard the "small mountain" concern raised by the Fort McKay Band as being environmentally significant since other undulating land forms characterize the general region.

## 9. RECLAMATION

### 9.1 Applicant's Views

The applicant stated that there is sufficient topsoil within the existing 25-year mine area to reclaim the proposed Site 6, hence topsoil removal from the site is not required. The applicant further stated that the

sodium-rich Clearwater clays, to be encountered in subsequent prestripping, would be buried within the site and therefore would cause no reclamation problems. The site would be reclaimed in accordance with revegetation plan objectives and methods already approved by the Land Conservation and Reclamation Council for other disposal sites.

### 9.2 Intervener's Views

The intervener suggested that further consideration of the proposed discard site should be withheld until fully documented plans for reclamation have been filed.

### 9.3 Board's Views

The Board believes that a satisfactory reclamation plan can be put in place for the kind of discard site described and this is confirmed by experience at other Syncrude sites. Indeed, the details of all aspects of reclamation activities are documented in the annual report submitted to the Land Conservation and Reclamation Council pursuant to Development and Reclamation Approval No. OS-1-78. Therefore, while the Board agrees with the Fort McKay Indian Band that a more extensive description of the reclamation plan would have been useful, it is satisfied that the detailed documentation would be submitted to the Land Conservation and Reclamation Council in the near future and that necessary reclamation requirements would then be established. The Board understands that the Fort McKay Band would also wish to examine and provide comments on the detailed documentation and, in this regard, would recommend that the Band arrange for this with the Land Conservation and Reclamation Council.

In the absence of a detailed reclamation plan showing topsoil volumes, the Board is not prepared to assume that growth media from Site 6 need not be salvaged for stability and reclamation. Indeed, the Board holds that the environmentally safe position would be to require the salvage and storage of available topsoil and muskeg unless it was clearly demonstrated to be unnecessary. An accurate estimate and evaluation of the topsoil and muskeg resources would be necessary both for detailed geotechnical design and for the reclamation plan required by the ERCB and the Land Conservation and Reclamation Council.

## 10 SOCIAL IMPACTS

### 10.1 Applicant's Views

The applicant stated that the proposed Site 6 would have a minor impact on Mr. F. Orr's trapline since the site occupies only about 0.5 per cent of his trapline area. By analogy there would be only a minor impact on the Fort McKay Community. The applicant further stated that the biophysical impact would be temporary and that the site would regain new wildlife capabilities shortly after the construction was complete.

Syncrude pointed out that mutually acceptable compensation agreements had been completed with other trappers on its lease area in previous years and that negotiations with Mr. Orr have been on-going for several years but remain unresolved. Syncrude indicated that it had offered both cash compensation plus guaranteed employment for five months per year until Mr. Orr reaches retirement age as a means of mitigating purported or real social impacts.

10.2 Intervener's Views

The Fort McKay Band stated that the proposed Site 6 was immediately adjacent to Mr. Orr's trapline and would therefore seriously affect his social and economic wellbeing. In addition, Mr. Orr maintains three cabins on the proposed site as bases for hunting and trapping in the area. The Band also stated that any reduction in the hunting or trapping yield suffered by Mr. Orr would consequently affect a number of the Fort McKay people since more than one family was dependent on the fur and meat harvested from the area.

The Band further stated that substantial portions of their land had already been taken away by previous Syncrude developments without adequate compensation. The Band contended that no acceptable mitigative measures have been produced to compensate for the destruction of the habitat that would result from the proposed development.

10.3 Board's Views

While the Board agrees that the Syncrude project has resulted in economic and cultural impact on the Fort McKay community, the effect of the proposed discard site seems to be, by comparison, of much smaller magnitude. The Board notes that both Syncrude and the Fort McKay Band regard the practical solution to be one of compensation, a matter which is not within the Board's jurisdiction. However, it appears that an early resolution of the issue in a spirit of goodwill would be most desireable.

11 SUMMARY

The Board concludes that there is a need for additional external overburden discard storage for the Syncrude mining operation in order to achieve reliability of the entire material management and reclamation program. The Board further concludes that there is some urgency for selection and proper design of a new discard site such that it can be available for use not later than 1985. Recognizing the tight application review schedule, and a number of unresolved aspects of site availability, including mineral and surface leases and land-clearing approvals, the Board doubts that access to the proposed site during the current winter season could be attained.

Regarding technical and economic site selection factors, the Board concludes that, excluding environmental and other surface access questions, Site 6 as applied for is the most advantageous from the viewpoint of the mine development plan.

With reference to geotechnical factors, the Board concludes that, since the amount of muskeg present on the proposed site has not been assessed and the requirement for ditching and drainage has not been determined, stability analyses for the site cannot be fully defined at this time. In addition, because a slope failure would pose serious safety and environmental risks, the Board believes that careful controls on construction rates and procedures would need to be established.

Regarding environmental matters, while the proposed site is quite large, the land impacts are relatively modest compared to the impact on the land of the overall Syncrude project and the Board believes that sound development and reclamation procedures would ensure that environmental integrity is maintained. The Board also believes that a satisfactory reclamation plan could be put in place for the discard site once the detailed documentation had been submitted to the Land Conservation and Reclamation Council. The Fort McKay Band could arrange with the Land Conservation and Reclamation Council to review and comment on the detailed documentation prior to site access and construction activities by Syncrude.

The Board notes that while the Syncrude project has produced both economic and cultural impacts on the Fort McKay community, the incremental effect of the proposed discard site would be of much lesser magnitude. Nonetheless, the question of compensation would have to be settled.

## 12 DECISION

Having regard for its findings and its responsibility under the Oil and Gas Conservation Act, the Board is prepared, subject to the approvals of the Minister of the Environment and the Minister of Energy and Natural Resources with respect to matters of the environment, and with the authorization of the Lieutenant Governor in Council, to grant the application and authorize it in the manner shown in the attached draft amendments to Approval No. 2959.

Dated at Calgary, Alberta, on 31 March 1983.

Respectfully submitted,

N. Strom, P.Eng.
Board Member

V. E. Bohme, P.Eng.
Board Member

R. Paterson, P.Eng.
Acting Board Member

APPENDIX I FORM OF APPROVAL

THE PROVINCE OF ALBERTA

OIL AND GAS CONSERVATION ACT

ENERGY RESOURCES CONSERVATION BOARD

IN THE MATTER of a scheme of Her Majesty the Queen in Right of the Province of Alberta as represented by the Minister of Energy and Natural Resources, Alberta Energy Company Ltd., Canada-Cities Service Ltd., Esso Resources Canada Limited, Gulf Canada Resources Inc., Hudson's Bay Oil and Gas Company Limited, PanCanadian Petroleum Inc., Petro-Canada Exploration Inc. and Petrofina Canada Inc. for the recovery of oil sands, crude bitumen or products derived therefrom.

AMENDMENT OF APPROVAL NO. 2959C

(Amending Approval No. 2959)

WHEREAS the Energy Resources Conservation Board is prepared to amend Approval No. 2959 subject to the conditions herein contained, and each of the Minister of the Environment and the Minister of Energy and Natural Resources, has given his approval thereof, hereto attached, insofar as the application affects matters of the environment.

THEREFORE, the Energy Resources Conservation Board, pursuant to the Oil and Gas Conservation Act, being chapter O-5 of the Revised Statutes of Alberta, 1980, and with the approval of the Lieutenant Governor in Council, number and dated , hereby orders as follows:

1. Board Approval No. 2959 is amended.

2. The sixth paragraph of the preamble is amended by striking out "The Oil and Gas Conservation Act, being chapter 267 of the Revised Statutes of Alberta, 1970" and by substituting "the Oil and Gas Conservation Act, being chapter 0-5 of the Revised Statutes of Alberta, 1980".

3. Clause 1, Subclause (1) is amended by adding

"(g) an application dated December 7, 1982, and supporting material marked as exhibits and evidence adduced at the hearing of the application, "

after Subclause (1)(f).

4. Clause 11 is amended by adding

"(3) The report required by Subclause (1) shall include a plan view drawing of the S5 discard site showing areas designated for storage of Clearwater clay material. "

after Subclause (2).

5. Clause 12 is amended by striking out Subclauses (2) and (3) and substituting the following:

"(2) The area shown outlined on the attachment hereto, marked Appendix C, and identified as Discard Site S5, is approved for the permanent storage of overburden materials removed from any mine pit developed in the area shown outlined on Appendix A to Approval No. 2959.

(3) Syncrude shall submit to the Board, for the Board's approval, prior to 31 December 1983, the following information for the discard site described in Subclause (2):

(a) an isopach map of the muskeg thickness;

(b) an isopach map of the Clearwater Formation underlying the discard site;

(c) a drainage plan if the muskeg is planned to be drained;

(d) a construction plan and rate of construction for each overburden lift placed on the site;

(e) a revised stability analysis for critical sections of the proposed site based on additional information with respect to muskeg and Clearwater thickness;

(f) any other information the Board may require.

6\. Clause 13 is amended by striking out Subclause (2)(g) and substituting the following:

"(2)(g) An environmental impact assessment for the proposed site and any alternative sites considered.

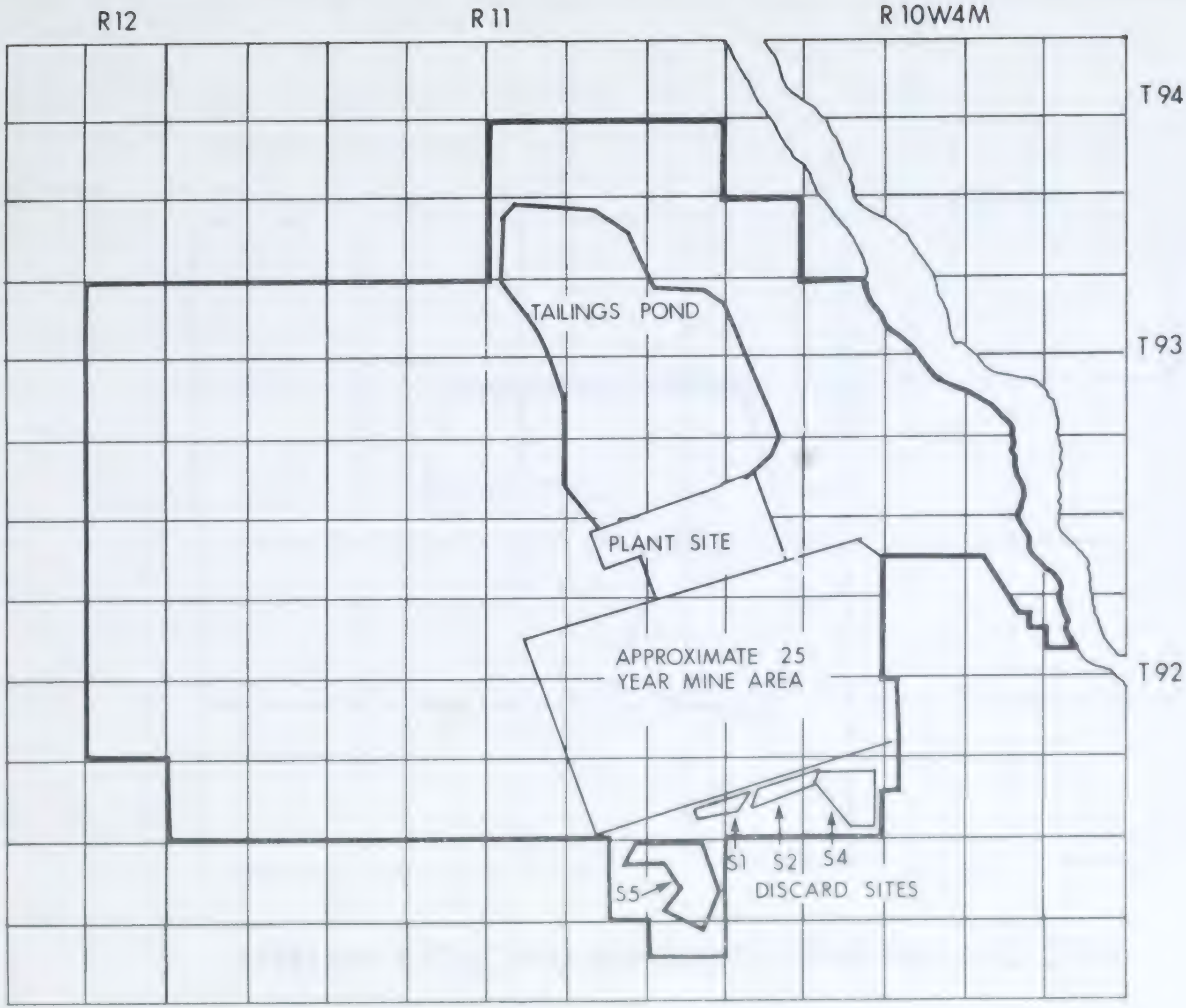
(h) A preliminary development and reclamation plan showing key aspects of site preparation and construction provisions.

(j) Any other information the Board may require. "

7. Appendices A, C and D are struck out and Appendices A, C, D and E hereto attached are substituted.

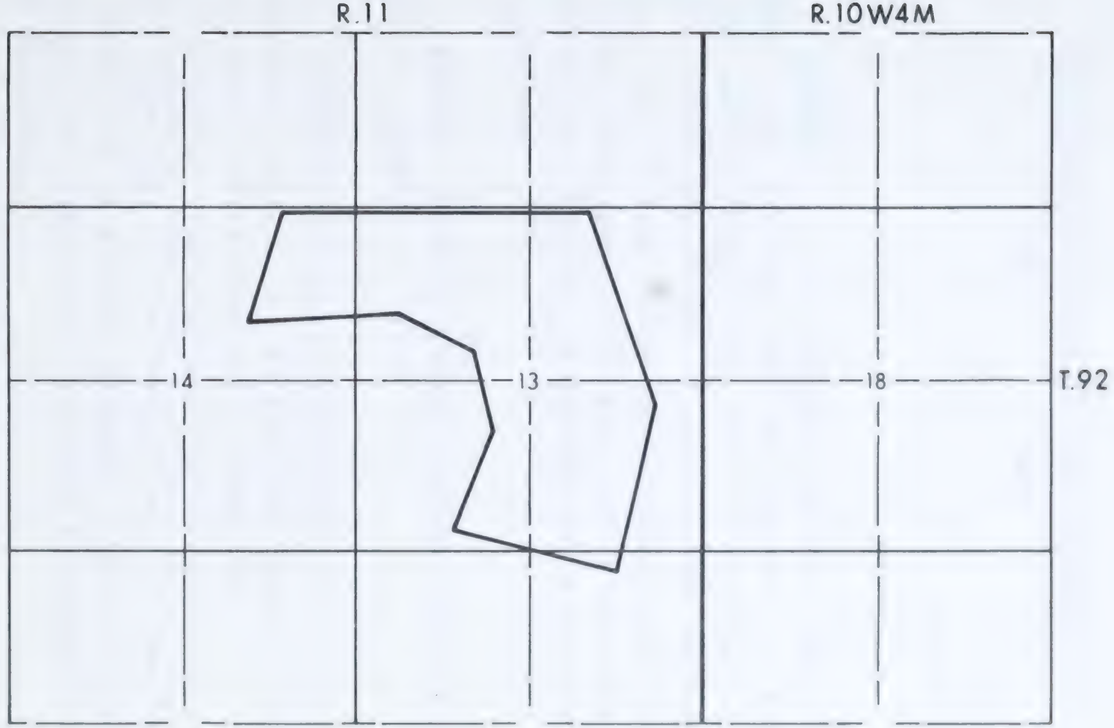
MADE at the City of Calgary, in the Province of Alberta, this day of , 1983.

ENERGY RESOURCES CONSERVATION BOARD




APPENDIX A TO APPROVAL NO. 2959
(PROJECT AREA AND APPROXIMATE SITE PLAN.)

ENERGY RESOURCES CONSERVATION BOARD




APPENDIX C (DISCARD SITE S5) TO APPROVAL NO. 2959

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA CANADA

APPENDIX D TO APPROVAL NO. 2959

Department of the Environment

M I N I S T E R I A L   A P P R O V A L

No.          ERCB

Edmonton, Alberta
19

WHEREAS I, I. W. Solodzuk, Deputy Minister of the Environment, have given my approval, pursuant to section 31 of the Oil and Gas Conservation Act, by Ministerial Approvals No. 79-171, 80-96 and 80-161 of applications by Syncrude Canada Ltd. to the Energy Resources Conservation Board in the matter of the operations of an oil sands processing scheme near Mildred Lake, insofar as they affected matters of the environment; and

WHEREAS Syncrude Canada Ltd. has applied for an amendment of Approval No. 2959.

THEREFORE, pursuant to section 31 of the Oil and Gas Conservation Act, I, I. W. Solodzuk, Deputy Minister of the Environment, hereby approve, in addition, Application 821217, registered on 14 December, 1982, by Syncrude Canada Ltd. to the Energy Resources Conservation Board, insofar as it affects matters of the environment, such application to be granted by the Board's Amendment of Approval No. 2959C.

Ministerial Approval No. 80-161 is hereby superseded.

DEPUTY MINISTER OF THE ENVIRONMENT

APPENDIX E TO APPROVAL NO. 2959

Department of Energy and Natural Resources

M I N I S T E R I A L   A P P R O V A L

No.        ERCB

Edmonton, Alberta
19

WHEREAS I, F. W. McDougall, Deputy Minister of the Renewable Resources, have given my approval, pursuant to section 31 of the Oil and Gas Conservation Act, by Ministerial Approvals dated October 10, 1979, April 2, 1980 and July 3, 1980 of applications by Syncrude Canada Ltd. to the Energy Resources Conservation Board in the matter of the operations of an oil sands processing scheme near Mildred Lake, insofar as they affected matters of the environment; and

WHEREAS Syncrude Canada Ltd. has applied for an amendment of Approval No. 2959.

THEREFORE, pursuant to section 31 of the Oil and Gas Conservation Act, I, F. W. McDougall, Deputy Minister of the Renewable Resources, hereby approve, in addition, Application 821217, registered on 14 December, 1982, by Syncrude Canada Ltd. to the Energy Resources Conservation Board, insofar as it affects matters of the environment, such application to be granted by the Board's Amendment of Approval No. 2959C.

Ministerial Approval dated 3 July, 1980 is hereby superseded.

DEPUTY MINISTER OF RENEWABLE RESOURCES

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

PUBLIC MEETING TO CONSIDER CONCERNS REGARDING THE DEVELOPMENT OF THE PROPOSED SADDLE RIDGE AREA

Decision D 83-6
Proceeding 821207

## 1 INTRODUCTION

The Energy Resources Conservation Board (the Board) received a request from the City of Calgary on 14 June 1982, to provide recommendations respecting the development of the Saddle Ridge area in northeast Calgary where there are a number of sour gas wells and pipelines. The Board considered the matter and subsequently met with City representatives on 14 September 1982 to discuss the Board's views. The Board then confirmed its position in a letter of 17 September to the City. The areas where the Board recommended that development not occur are shown in Figure 1 and generally reflect a separation distance of 0.5 kilometres (km) between residential development and existing sour gas wells and pipelines. The Board's letter also set out alternatives to illustrate setback distances between possible relocated sour gas facilities and proposed residential development.

As a result of the September 17 letter, the Board received a letter from Mr. A. Froese of Kentron Development Corporation Ltd., which requested that a meeting be arranged to discuss the proposed setback distances. A meeting was then held to review the matter with representatives of the land developers, gas operators, City of Calgary and the Board attending.

At that meeting, it was decided to defer consideration of the setback distances and schedule a public meeting where all interested parties could present their views to the Board. The public meeting took place in Calgary on 25-26 January and 14-15 March 1983 with V. Millard, G. J. DeSorcy, P.Eng. and V. E. Bohme, P.Eng. sitting. Appendix A is a list of those who appeared at the meeting.

## 2 LEGISLATION

Requirements governing separation distances between sour gas facilities and land development are enacted by both the ERCB and the Alberta Planning Board.

The current minimum distance requirements for separating new sour gas facilities from existing residential and other land development are set out in the ERCB's Interim Directive ID 81-3. The separation distance is a function of the volume or rate of hydrogen sulphide ($H_2S$) that could be released in case of a malfunction of the facility.

The Subdivision Regulations made pursuant to the Planning Act, 1977, set separation distances for new residential or urban developments from existing sour gas facilities identical to those in ID 81-3. It also grants the

ERCB the authority to designate the levels of sour gas facilities for separation purposes.

For subdivision applications, the Board furnishes the Subdivision Approving Authority with the classification of the sour gas facility and if necessary, associated recommendations. The Subdivision Approving Authority considers the recommendations of the Board as well as other referral authorities, but is not bound by them.

## 3 BACKGROUND ON SADDLE RIDGE

The Saddle Ridge area, shown on Figure 1, encompasses approximately 1130 hectares in the northeast corner of the city. The present land use is generally agricultural with limited residential acreages. There is some light industrial usage in the western portion of the Saddle Ridge area.

### 3.1 Sour Gas Facilities and Remaining Reserves

There are five producing sour gas wells within the boundaries of the proposed Saddle Ridge area development, four wells within the city and a fifth well outside the present city boundaries. The wells are producing from the Rundle B and Basal Quartz pools and one is injecting water into the Wabamun A Pool. The hydrogen sulphide content of the pools is very low, ranging from 0.4 per cent to 1 per cent, and the sour gas is transported by pipelines through the proposed Saddle Ridge area to the Petrogas processing plant located 5.5 km north of the area. The wells and pipelines are shown on Figure 1.

Production of gas from the area commenced in 1963 and the time of abandonment of the area is expected to be between 15 and 20 years hence. The following table details the producing pools for each well and their estimated life expectancy as calculated by Petrogas, Cathton and the Board. It also shows the remaining marketable reserves as estimated by the Board, assuming that production would continue until the time of normal economic abandonment.

TABLE I SADDLE RIDGE WELLS
Estimated Life Expectancy
and Remaining Marketable Reserves

| Well (Abbreviation) | Producing Pool | Life Expectancy | | | Remaining Marketable Reserves |
|---|---|---|---|---|---|
| | | Petrogas[a] | Cathton | ERCB[b] | |
| | | Years | | | $10^6 m^3$ |
| 01-09-25-29 W4 (1-9) | Rundle B | 3-5 | | 4 | 30 |
| | Bsl Quartz B | | | 10-15 | 65[c] |
| 10-10-25-29 W4 (10-10) | Bsl Quartz B | 1-2 | | 3 | 3 |
| 11-11-25-29 W4 (11-11) | Rundle B | 5-10 | | 12-15 | 157 |
| 04-15-25-29 W4 (4-15) | Rundle B | 10-15 | | 15-19 | 456 |
| 11-13-25-29 W4 (11-13) | Rundle B | 3-5 | 15 | 11-13 | 64 |
| | Wabamun A | d | | | |
| | | | | TOTAL | 775 |

a. The higher number assumes that wells are shut-in for part of the year while the lower number assumes continuous production.

b. Assumes continuous production throughout the year. The higher number assumes reduced production rates due to possible water problems late in the life of the well.

c. Recompletion required.

d. The 11-13 well is also used for Crossfield sour water injection into the Wabamun A Pool. This is one of two disposal wells that is critical to the operation of the plant and therefore the life of the well will be that of the plant.

The table indicates the relative importance of the 4-15 well from which it is estimated that approximately 60 per cent of the remaining reserves in the Saddle Ridge area may be recovered and the 11-11 well where approximately 20 per cent of the reserves may be recovered.

### 3.2 Saddle Ridge Development Proposal

Carma and Kentron indicated that the Saddle Ridge area should be developed commencing in 1984 or 1985 to fill a need for affordable housing in the northeast corner of the city. Although the two firms have interest in only some 450 hectares of the area, they have designed a development plan (Figure 2) which encompasses all land within the Saddle Ridge area, including the land owned by Cathton which is presently outside the city limits. The plan calls for construction of about 2500 residential units per year with an ultimate population for the Saddle Ridge area of some 60 000 people.

The City of Calgary agreed with the developers that the northeast is an economical area for expansion of the city because for the most part, it is readily serviceable. The City indicated that while the land is not urgently needed for development given the present market conditions, the need for a decision on setback distances is urgent because the planning process is lengthy.

### 3.3 Responses to Recommended Setback Distances

In the Board's letter of 17 September 1982 to the City of Calgary, a setback from the sour gas pipelines of 350 to 500 metres was proposed. The Board considered it appropriate to recommend larger separation distances than specified in ID 81-3 because it was concerned that high density urban development should not be located adjacent to and surrounded on most sides by sour gas wells and pipelines. The separation distances recommended by the Board were generally the next higher sour gas level than required by ID 81-3. For example, where the potential sour gas release volume was such that the facility qualified as a Level 1 facility, the Board used the separation distance for a Level 2 facility.

The developers indicated that the increase in setback distances required in the Board's 17 September letter sterilized in the order of 300 hectares from development, thereby rendering the entire Saddle Ridge area economically undevelopable. In addition, the developers suggested that the large separation distances could affect the Martindale subdivision located directly south of Saddle Ridge because servicing of the northern portions of that area might not be possible.

Certain landowners in the area expressed concern over the large setbacks and indicated that the wells should be abandoned or relocated. They stated that if they are denied their right to develop their land, due to the existence of sour gas facilities, the economic penalty should be assessed against the sour gas operator. They suggested that a cost/benefit analysis should be made to determine priorities by assessing the economic benefit accruing from the gas production compared to the economic cost suffered by the landowner.

Petrogas contended that the setbacks should be at least the 500 metres recommended by the Board to protect the public. It argued that the effect

of reduced setbacks may be the early shutdown of sour gas facilities and the loss of reserves.

The City of Calgary indicated that it would rely on the Board's recommendation for the determination of the appropriate setback distance.

## 4 ISSUES

The Board considers the major issues to be:

- o the appropriate separation distances from the existing sour gas facilities in Saddle Ridge,
- o the need for special provisions within the setback area,
- o the need for restrictions on the sour gas operations in the area having regard for competing land use,
- o the need for phasing residential development with the depletion of the gas reserves.

### 4.1 Separation Distances

Participants' Views

All participants indicated that residential development in Saddle Ridge should be separated from sour gas facilities. However, there was disagreement with respect to the appropriate setback distance with suggestions ranging from 20 metres to 500 metres or greater.

Dr. Leahey on behalf of Carma and Kentron suggested that the worst case scenario, as proposed by Petrogas, should not be used. Rather, he argued that the setback distance should be established by assessing personal risk and overall consequences of a sour gas release. He contended that a study of these matters indicates no serious risk or consequence to the public beyond some 20 metres from the pipelines.

The developers in general suggested the setback distance for Saddle Ridge should recognize that the sour gas content is barely one per cent and the $H_2S$ release volumes for the wells and pipelines are low in comparison to the lowest category release (Level 1) specified in the Board's ID 81-3. The developers therefore proposed a 20-metre setback from the pipelines and a 100-metre setback from the wells.

The landowners generally supported Carma and Kentron while Mr. Longpre, representing the Saddle Ridge Business Association, suggested that if light industrial use, primarily outside storage, was not permitted within the setback area, the separation distance should be limited to the pipeline right of way.

Petrogas suggested that the Board recommend setbacks which correspond to the 100 parts per million (ppm) $H_2S$ isopleth utilizing a worst case scenario. It stated that the primary issue is safety and due consideration must be given to the number of people exposed to sour gas from a well or pipeline failure. It was also concerned with the compatibility of sour gas producing

operations with urban development in terms of noise, odours and general activity. Petrogas therefore favoured a setback of at least 500 metres from the pipeline.

The City indicated that it would rely on the advice of the Board. It asked the Board to include recommendations respecting the Level 3 and Level 4 facilities outside the corporate City limits to the east and north of Saddle Ridge, as well as for the facilities within Saddle Ridge.

Board's Views

The Board does not believe that separation distances should be based on the calculated 100 ppm isopleth. One reason for this is the wide range in estimates for the 100 ppm isopleth depending upon the assumptions used in its derivation. Petrogas suggested that a worst case analysis be used to calculate the isopleth, but in the Board's view, this is an unnecessarily restrictive method of determining potential impact in that it assumes every possible factor would be at its worst at the same time. Such an approach reduces the risk of being in an area near sour gas facilities to much less than is faced from even the most remote hazards in modern society. Indeed this was the reason the Board discontinued the use of the isopleth distance when it issued ID 79-2 in 1979 (ID 79-2 was superseded by ID 81-3 in 1981).

As a result of the concerns expressed and information supplied at the meeting, the Board has reviewed the separation distances outlined in its September, 1982 recommendation to the City. Having regard for the $H_2S$ release volumes and the risks and consequences, the Board concludes that the recommended setback distances were unnecessarily large.

The most significant factors which led the Board to this conclusion relate to the $H_2S$ content of the gas and to the possible $H_2S$ release volumes for the facilities in the area. The $H_2S$ content and release volumes associated with the wells and pipelines are at the lower end of the Level 1 classification set out in ID 81-3. This would suggest that the separation distances for Level 1 facilities, 100 metres for wells and the right of way width for pipelines, would be adequate.

With respect to wells and having regard for their capability to produce and the $H_2S$ content of the gas, the Board is satisfied that the 100-metre setback for urban development would not jeopardize public safety.

In this area, the pipeline right of way is generally 13.7 metres wide so the ID 81-3 setback distance from a pipeline in the middle of the right of way would likely be less than 7 metres. The Board does not consider this would be adequate, not so much because of possible danger to the public due to $H_2S$ if a release occurred, but primarily because the setback distance is not adequate in terms of reducing the chances of third-party damage to the pipelines during the heavy development period. Section 28.1 of the Pipeline Regulations establishes a controlled area of 30 metres to minimize chances of third-party damage. The Board believes this is the separation distance that should be maintained from the sour gas pipelines in Saddle Ridge.

The above conclusions that 100 metre and 30 metre separation distances are, respectively, adequate for the existing wells and pipelines, are based on concerns for an acceptable level of safety for the public. The Board does recognize that such separation distances would likely result in nuisance type impacts, such as odours and noise, on nearby residents. To minimize these impacts and also to further reduce the risk to public safety, the Board believes that the chances of an uncontrolled release should be reduced by requiring special precautions to protect the sour gas facilities from third-party damage. The consequences of a release, in the unlikely event that one did occur, could also be reduced by ensuring that all safety features to limit release volumes are installed and properly operating. These special precautions are discussed further in Section 5.

The City asked the Board to comment respecting separation distances for the Level 3 and 4 facilities east and north of the Saddle Ridge area and in particular, as to whether these would impact on the area. The Board continues to be of the view that the minimum separation distances prescribed in ID 81-3 are appropriate for the sour gas facilities outside the corporate limits of Calgary. Since the Level 3 facilities in question are more than 1.5 km removed to the east and the Level 4 facilities are approximately 5 km to the north of the Saddle Ridge area, the Board sees no need for special restrictions for Saddle Ridge beyond those set out in the ID. Additionally, the major concern related to increased ground disturbance during construction would not be a problem with respect to the sour gas pipeline outside of the City.

## 4.2 Land Use within the Restricted Area

The Board notes the uncertainty of the developers, landowners and planners over permitted land use within the setback areas.

Participants' Views

The developers in their preliminary plans, proposed roads, underground services, parks and school grounds within the proposed 20-metre setback. Mr. Longpre suggested that outside storage should be permitted within the setback area up to the pipeline right of way.

Board's Views

In view of the reduced setback distance, the Board is of the opinion that public and industry use of the land within the restricted area should be limited as much as possible. The Board believes that it is not appropriate for any buildings to be located in the setback area, nor is it appropriate to have roads or major utilities parallelling the pipeline within the setback. These measures would reduce the possibility of third-party damage to the pipelines during the construction or post-construction phases.

The Board believes the setback area could be used as green areas, but centres for public gatherings such as parks and playgrounds should be avoided. Where public facilities, such as schoolgrounds and parks abut the setback area, they should be separated by permanent fencing. Limited

industrial outside storage could be permitted up to the pipeline right of way provided no ground disturbance would be associated with the industrial activity.

## 4.3 Restrictions on Sour Gas Operations

As indicated in Section 4.1, the Board is satisfied that existing sour gas operations and urban development could co-exist without serious risk to the public safety. There would, however, be nuisance impacts of the sour gas operations on residents of the area. For this reason, and because certain surface owners suggested that wells could be abandoned to avoid land use conflicts, the Board is dealing with this matter.

### Participants' Views

Petrogas argued that there was a significant amount of gas to be recovered and it was not prepared to abandon the wells without suitable compensation.

All participants agreed that it was in the interests of everyone to deplete the reserves as soon as possible, thereby allowing the reserves to be recovered and not creating undue hardship on the landowners. Petrogas indicated that it was actively pursuing the possibility of accelerated depletion for the wells in the Saddle Ridge area.

### Board's Views

The Board considers the remaining marketable reserves under the Saddle Ridge area to be significant, almost 800 x $10^6 m^3$ of gas worth in excess of $80 million at current prices, and therefore concludes that abandonment of the wells at this time would not be appropriate. The Board has also made an assessment of the degree to which reserves would be lost if abandonment were to take place prematurely but at future dates as urban development proceeded. The analysis assumed that gas production would be feasible on a continuous basis and indicated that if abandonment occurred in 1986, some 300 to 500 x $10^6 m^3$ of gas worth about $40 million would be ultimately lost. If abandonment occurred in 1990, some 200 to 300 x $10^6 m^3$ of gas worth some $25 million would be lost. The lower limit of these calculations assumed that some drainage from beneath the Saddle Ridge area would occur towards an existing northern well.

Given the economic loss from early abandonment of wells in the area and that urban development could proceed economically with separation distances which would not jeopardize public safety, the Board concludes that premature abandonment of wells in the area would not be in the public interest.

Bearing in mind the nuisance impacts that would result from co-existence of gas operations and urban developments, the Board agrees with the participants that rapid depletion of sour gas reserves in or near urban areas is desireable and believes that Petrogas should continue to actively pursue measures towards this end. The Board notes the Petrogas estimate

of a one-third reduction in life if the wells are produced year round. It expects that a further reduction in life may be possible if the production rates can be increased.

The Board recognizes the difficulty described by Petrogas of producing the subject wells at full capacity given the existing marketing problems respecting Alberta gas and the substantial shut-in reserves. If voluntary arrangements cannot be made that would allow rapid production of the reserves in question, it may be necessary for the Board to seek an amendment to legislation that would allow it, with the approval of the Lieutenant Governor in Council, to direct the rates at which gas must be purchased from areas such as Saddle Ridge.

## 4.4 Phasing Urban Development

The possibility of phased urban development has the potential to reduce the time span over which co-existence and the related nuisance problems would be necessary.

### Participants' Views

The developers, landowners and the City indicated that it was not appropriate, as Petrogas suggested, to delay urban development until the reserves are depleted. Carma and Kentron submitted that there was a need for inexpensive housing in northeast Calgary that could not be provided elsewhere in the City.

As an alternative to restricting urban development for the entire Saddle Ridge area, Carma/Kentron suggested a phased development where urban expansion would take place as the wells are abandoned. Utilizing the Petrogas abandonment estimates, Carma/Kentron submitted a phased-development plan whereby areas not affected by large setbacks and areas freed up by well abandonments would be developed first. The plan is summarized in Figure 2, and suggests that development could take place in areas 1 and 2 during the 1980s, but by 1989/90, the original ERCB recommended setback from the 11-11 well would place restrictions on future construction possibilities.

### Board's Views

The Board believes that a phased development plan to minimize co-existence is not required for public safety but would be desirable to avoid nuisance impacts on residents from the sour gas facilities. Phased development would lower the impact of the noise and odours created by well workovers, flaring and day-to-day sour gas operations.

The Board notes from a comparison of Table 1 and Figure 2 that there is considerable scope to phase developments and minimize impacts during the 1980s. Thereafter the importance of the 4-15 and 11-11 wells, in terms of gas recovery, would mean that co-existence will be necessary if residential developments proceed as planned. The Board does not consider this a serious problem but believes that developers, city planners and Petrogas

should co-operate to minimize potential conflicts through a co-ordinated development approach.

## 5 SPECIAL MEASURES TO MINIMIZE THE IMPACT OF SOUR GAS OPERATIONS AND THE CHANCES OF A RELEASE

In addition to the subject of separation distances, measures such as notification and safety procedures were discussed at the meeting. The Board considers these to be an inherent part of its recommended reduction in separation distances and, consequently is dealing with them in this report. Where the Board has jurisdiction, it intends to impose the special safety measures and, for those controlled by the City, it recommends adoption by that jurisdiction.

### 5.1 Notification

Participants' Views

Petrogas suggested that the public should know that sour gas wells and pipelines are in the vicinity of their dwellings so as to improve their awareness with respect to odour, noise, flaring and response to an emergency. Mr. Froese suggested a caveat could be placed on the land title informing the potential buyer.

Board's Views

The Board supports the concept of informing prospective purchasers and residents regarding the present sour gas facilities in the area but it questions the applicability of such a caveat on land titles. An alternative action which the Board believes the City should consider is an information package that would be developed jointly by a committee that includes the sour gas operator, the City, the developers and the Board. The information package would be made available to prospective purchasers and distributed to residences on a regular basis. The package should clearly set out the existence of the sour gas facilities and should describe expectations and procedures regarding nuisance problems such as odours, noise and flaring.

In the Board's view, the information package should be funded by the developers.

### 5.2 Safety Procedures

Participants' Views

The developers outlined a number of measures that could be taken to protect the sour gas facilities during the construction and post-construction periods. These include:

- o Fencing the pipeline right of way until the housing in the area is completed.

- o Making vehicle access to the right of way impossible except in a controlled manner.
- o Utilizing ramps where equipment must cross the pipeline right of way.
- o Requiring excavations at pipeline crossings to take place prior to the construction of housing near the area.
- o Utilizing an absolute minimum number of crossings.
- o Utilizing full time inspectors for major excavations near pipelines.
- o Imposing strict control measures to protect the pipelines at all times during construction.
- o After construction, placing signs in the vicinity of the pipelines and installing underground tapes to mark their locations.

If further precautions are required, the developers suggested that they should be recommended by a utility co-ordinating committee made up of representatives of all involved parties.

Petrogas briefly outlined some of its crossing procedures including the accurate location and staking of pipelines, fencing of pipeline right of way, liaison on a daily basis, establishment of a surveillance system and the possible depressuring of pipelines when crossings are to be installed.

Petrogas indicated that it has a good safety record and must maintain it long after the developer has concluded operations, suggesting that it would be responsible for surveillance and responses to complaints after the construction period. In addition, Petrogas indicated that only the 4-15 well in the Saddle Ridge area has an emergency downhole safety valve and agreed that it may be a good idea to install downhole valves in the other wells if the population increases.

Board's Views

The Board notes that many of the construction precautions that were mentioned at the meeting are required by the Pipeline Regulations and are current practice. However, the Board agrees that for the sour gas facilities under discussion, the additional measures suggested by the developers and operators are appropriate and should be implemented. Details should be submitted to the City, the gas operator and the Board prior to construction and should include all of those suggested earlier by the developers. The Board believes that the cost of these measures, taken to protect the sour gas facilities from ground disturbance, should be borne by the person responsible for the ground disturbance.

The Board considers it appropriate for the operator to install downhole safety valves for the wells in Saddle Ridge at the time of the next workover and no later than the residential development stage in the immediate area. The Board will impose this requirement on the gas producers.

If residential development goes ahead in the subject area prior to the abandonment of the gas wells, the Board suggests that a special liaison committee be established by the City of Calgary. It should be made up of representatives of the gas producers, land developers, residents and landowners in the area, the City and the Board. In addition to co-ordinating the preparation of the previously mentioned brochure and special measures during construction, it would deal with ongoing complaints or procedures for notifying the public of flaring operations and other relevant matters, and where necessary, would recommend further actions to those having jurisdiction.

The Board would not expect the costs associated with the committee to be significant and would expect them to be generally covered by the participants in the committee. The Board considers it important that the developers' involvement with the committee be maintained after the lands have been developed and disposed of to contractors or individual residents.

## 6 RECOMMENDATIONS

The Board recommends that the City adopt, for the Saddle Ridge area, separation distances between residential development and sour gas facilities of 100 metres for the wells and 30 metres for pipelines.

The Board further recommends that the City consider for adoption the suggestions set out in this report regarding land use within the restricted area, notification of prospective purchasers and residents, safety procedures during construction and formation of a liaison committee.

ISSUED at Calgary, Alberta, on 8 June 1983.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

G. J. DeSorcy, P.Eng.
Vice Chairman

V. E. Bohme, P.Eng.
Board Member

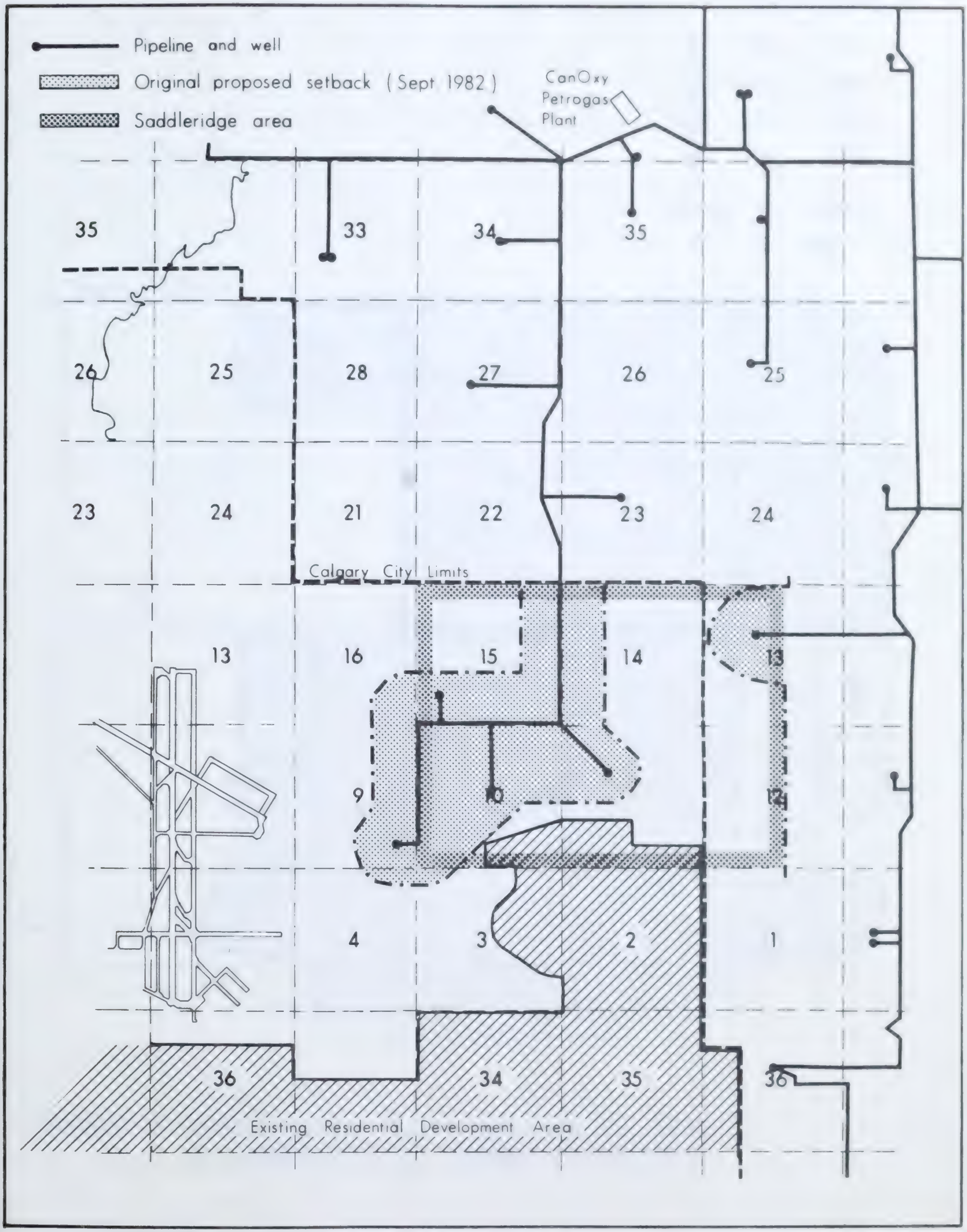



FIGURE 1 SADDLERIDGE AREA

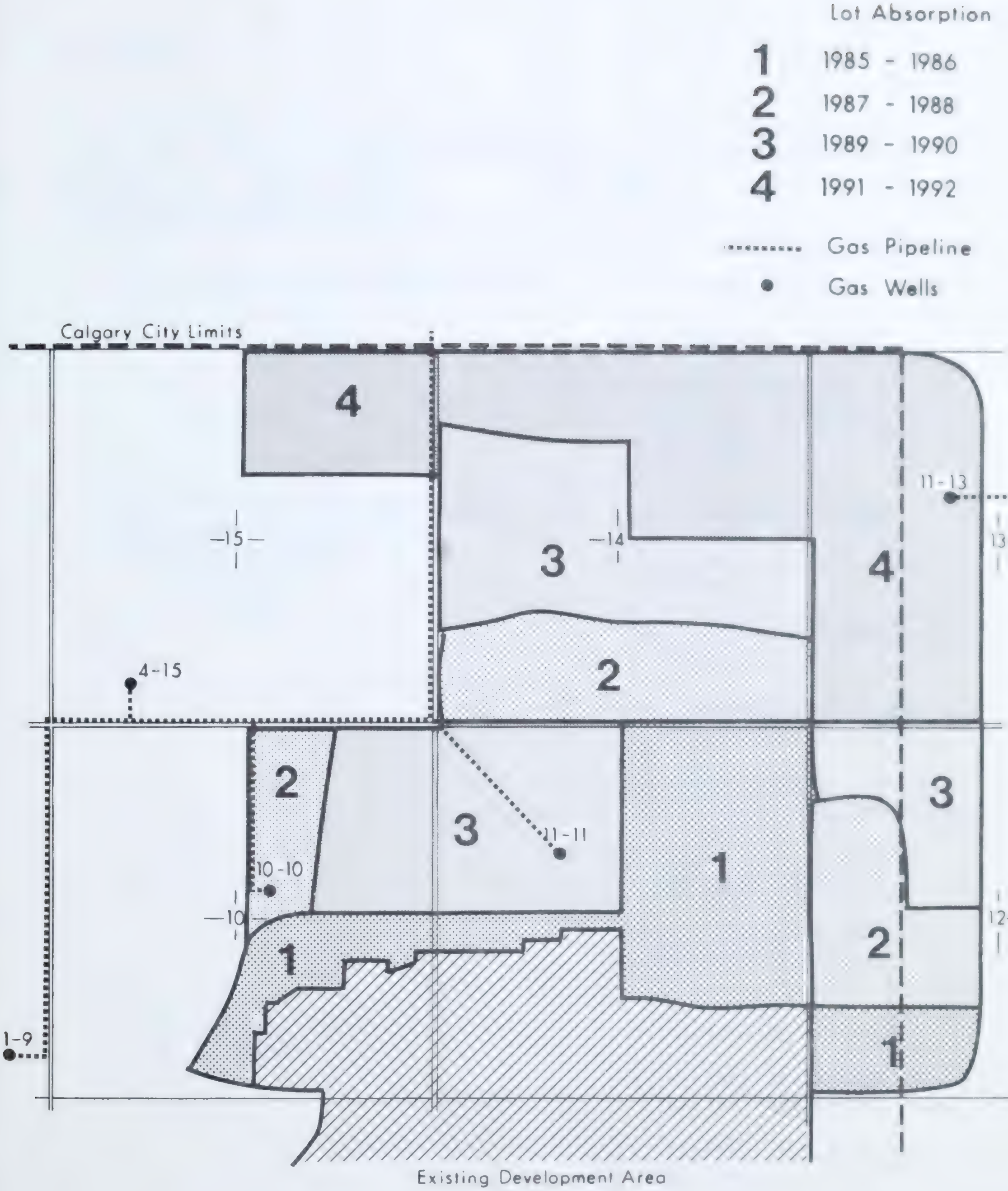



FIGURE 2 DEVELOPMENT PLAN SADDLERIDGE AREA
AS SUBMITTED BY CARMA & KENTRON

APPENDIX A

## THOSE WHO APPEARED AT THE MEETING

| Principal and Representatives (Abbreviations used in Report) | Witnesses |
|---|---|
| City of Calgary Planning Department (City) | T. Brown, M.C.I.P.<br>B. Simpkins, M.C.I.P.<br>P. Dack, M.C.I.P.<br>Captain M. MacKenzie of the City of Calgary Fire Department |
| Carma Developers Ltd. and Kentron Development Corporation Ltd. (Carma and Kentron)<br>M. Saville<br>R. Neufeld | A. Froese of Kentron<br>E. Ayerst, M.C.I.P. of Carma<br>Dr. D. Leahey of Western Research<br>G. Brown of Stanley and Associates<br>F. Grigel, P.Eng., M.C.I.P. of Stanley and Associates<br>C. Van Bussel of Stanley and Associates<br>Dr. C. Swoveland of Quantalytics Inc. |
| Cathton Holdings (Cathton)<br>D. G. Ingram | R. A. Manning<br>J. K. Farries, P.Eng. of Farries Engineering Ltd.<br>P. English, M.C.I.P. of Plan West |
| Qualico Developments | W. Richter |
| Oscar Fech Construction Ltd. | O. Fech |

| | |
|---|---|
| Longpre Associates | J. C. Longpre, M.C.I.P. |
| A. E. Manz | A. E. Manz<br>R. L. Manz, P.Geol. |
| 219575 Alberta Ltd. | M. Sardachuk of Meteor Developments Limited |
| Saddle Ridge Community Association | C. Jacobsen |
| Petrogas Processing Ltd. (Petrogas)<br>D. Parsons | R. H. Orthlieb, P.Eng. |
| | G. Simpson, P.Eng.<br>W. Van der Linden |
| | Dr. E. K. Enns of the University of Calgary |
| | Dr. E. Leavitt of Interra Environmental Consultants Ltd. |
| | K. Grandid of Interra Environmental Consultants Ltd. |
| Board Staff<br>M. Bruni<br>W. G. Remmer, P.Eng.<br>C. McKay | L. Holizki, P.Eng. |
| | Dr. R. Purvis, P.Eng. |
| | W. E. Roberts, E.I.T. |

Mr. Allen filed an intervention but did not appear at the meeting.

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

THE CITY OF EDMONTON
500 kV TRANSMISSION LINES
GENESEE AREA

Decision D 83-7
Application 810932

The Board has reviewed the report of its Examiner, attached hereto, respecting Application 810932 by the City of Edmonton for approval to construct and operate a substation and switchyard at Edmonton Power's Genesee power plant, and for two single circuit steel tower transmission lines to connect the switchyard to TransAlta Utilities' existing 500 kV transmission lines CP 1203L and CP 1209L.

For the purposes of its decision, the Board adopts the Examiner's recommendations.

DATED at Calgary, Alberta, on 27 May 1983.

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy
Vice Chairman

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

THE CITY OF EDMONTON
500-kV TRANSMISSION LINES
GENESEE AREA

Examiner's Report E83-11
Application 810932

## 1 INTRODUCTION AND BACKGROUND

The City of Edmonton applied under sections 12, 14 and 17 of the Hydro and Electric Energy Act for permits and licences to construct and operate a switchyard at Edmonton Power's Genesee power plant and two single circuit steel tower transmission lines which will be used to connect from the switchyard to TransAlta Utilities' existing 500-kV transmission line 1203L - 1209L, located 5.2 kilometres away. Both switchyard and the transmission line are to be operated at 500 kV.

The City of Edmonton has already obtained approval for Edmonton Power to construct and operate its Genesee power plant.[1] The Board, in its Decisions 80-A and 81-D, approved the construction and operation of TransAlta's 500-kV lines; and in 81-D, page 17, stated that the City of Edmonton should connect the Genesee power plant to the Alberta system via TransAlta's 500-kV system.

Figure 1 shows the route of the proposed transmission line, and Figures 2 and 3 show alternative routes investigated by the applicant.

The application was considered by the Board at a public hearing in Edmonton on 7 April 1983 before Examiner C. J. Goodman, P.Eng.

The Table lists those who appeared at the hearing, along with abbreviations used in this report.

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1 By ERCB Decisions 80-B and 82-C and Approval HE 8215

THOSE WHO APPEARED AT THE HEARING

| Principals and Representatives (Abbreviations used in Report) | Witnesses |
|---|---|
| City of Edmonton or Edmonton Power<br>M. Sherk | D. J. Pelletier, P.Eng.<br>F. Kardel, P.Eng.<br>D. B. Ramsey, of Stanley-IEC |
| E. R. Litzenberger<br>M. Litzenberger | M. Litzenberger |
| TransAlta Utilities Corporation (TransAlta)<br>H. D. Williamson | W. Nieboer, P.Eng. |
| J. Comeau | J. Comeau |
| Alberta Environment<br>R. Grover | |
| Energy Resources Conservation Board staff<br>K. F. Miller<br>T. Chan, P.Eng.<br>D. Beamer, C.E.T. | |

## 2 THE ISSUES

As outlined in the Introduction and Background, the Board had previously directed that electric energy from the Genesee power plant should enter the Alberta system via the approved 500-kV lines between TransAlta's Keephills power plant and Edmonton. The Examiner finds nothing in this application and in the evidence submitted that would suggest that this decision should be altered, and therefore believes that the need for the proposed lines has been established.

Considering the Board's responsibilities under the Hydro and Electric Energy Act, the Examiner believes the remaining issues to be:

- the reliability of the proposed substation configuration and line arrangement; and

- the route proposed for the two transmission lines.

## 3 RELIABILITY OF THE PROPOSED SUBSTATION CONFIGURATION

### 3.1 Views of the Applicant

Edmonton Power stated that its arrangement of breakers, as shown in

Figure 4, would provide maximum reliability and operational flexibility. It explained that although the proposed circuit breaker arrangement had a higher risk of losing both generating units, it would allow a proper division of operating responsibility between plant operators and system operators. Edmonton Power submitted that the latter benefit, while difficult to quantify, could outweigh the reliability considerations associated with the switching configuration. Furthermore it was of the opinion that the Alberta system, supported by potential assistance from B.C. Hydro over the 500-kV tie-line, could experience a loss of both Genesee generating units without a cascading outage of other generating units on the Alberta system. It provided a transient stability analysis that estimated assistance in the order of 800 MW from the B.C. system. It also noted that any reduction in reliability due to the switching arrangement proposed could be of relatively short duration until such time as the station expanded and future circuit breakers were installed.

## 3.2 Views of the Interveners

TransAlta referred to a lengthy period of discussions with Edmonton Power about the method of operation of the Genesee plant substation, and TransAlta's understanding that there would be an interim period during which TransAlta would handle system operations until a central system authority was established by the operating utilities.

Other interveners did not express views on this subject.

## 3.3 Views of the Examiner

The Examiner accepts that reliability aspects of both substation design and system operation are important considerations for achieving a reliable power system, and believes that only when the respective reliability objectives of design and operation cannot both be fulfilled at reasonable cost should a compromise be made.

The Examiner has considered alternative breaker arrangements within the substation and observes that, ignoring for the moment the separation of plant and system operations, the arrangement proposed by the applicant is one of the least reliable of several possible switching configurations. There are probably a number of either forced outages or scheduled maintenance outages which, if overlapped by a second forced outage, could cause total shut-down of the station and loss of both Genesee generating units to the Alberta system. Such a double event is presumed to be quite rare but is, nonetheless, a cause for concern. Whether such an event, when it did occur, would cause further outages on the Alberta system would be a function of the dispatch of the system prior to the outage and measures taken by the operating utilities to mitigate such a situation.

The Examiner questions whether transient power transfer to the Alberta system would always be available, especially assistance to a level of about 800 or more megawatts inflow to Alberta. The amount of assistance available and needed over the tie-line from the British Columbia system

would likely depend on the state of that system at the time assistance was required, dispatch of such items as spinning reserve on the Alberta system just prior to the need for assistance, and whether the scheduled flows on the tie-line were either into or out of Alberta. In spite of the studies that have been carried out by Edmonton Power, this introduces a degree of uncertainty as to the vulnerability of the Alberta system to the simultaneous loss of both Genesee generating units.

The Examiner also considered the reliability aspect of the proposed switching arrangement if the Genesee substation should be expanded in the future to include two additional generating units. Possibly some short-term improvement in reliability might be realized by early installation of future breakers but inevitably the arrangment would revert to that proposed now, and with four instead of two generators vulnerable in the two-line situation.

Decision 80-A approved two 500-kV lines between Keephills and Edmonton that would have sufficient capacity to serve eight generating units in the Wabamun area. Because of the high concentration of electric energy to be transmitted east over this 500-kV system, the Examiner believes that proposed facilities to be interconnected into this system should not impair its overall security. The Examiner also notes that TransAlta, at its existing Keephills substation and in additions proposed in Application 820942, is proposing that switching of the 500-kV lines at the Keephills substation would be similar to that shown in Figure 5.

Installation of generator breakers for the Genesee units, as shown in Figure 5, would provide the required clear demarcation point between plant and system operations, and would also allow flexibility in positioning the generator and line entrances to achieve the best reliability from the breaker arrangement without intermingling plant and system control of breakers. It could eliminate the most probable double contingencies, and scheduled maintenance over-lapping with a forced outage, as causes of total shut-down of the proposed substation.

The Examiner is thus of the opinion that installation of generator breakers at Genesee would facilitate achievement of the highest possible reliability from the chosen breaker arrangement, provide clear interface points between plant and system operations, and would be consistent with the present and proposed practice of the other utility operating the same transmission system. Having considered all of the above, the Examiner therefore believes that Edmonton Power should include generator breakers and alternate the generator and line entrances in its Genesee substation configuration.

## 4 ROUTE

### 4.1 Views of the Applicant

Edmonton Power examined three routes which it designated as Routes 1A and 1B, and Route 2. Its reasons for proposing to construct Route 1A

are outlined in its application and were discussed at the hearing.

Edmonton Power's application included an environmental report that analyzed and evaluated factors affecting route selection. It used a weighted matrix approach to compare 16 factors in the categories of physical environment, natural environment, existing land use, proposed land use and visual and aesthetic concerns. The category of existing land use included consideration of occupied dwellings, heritage resources, agriculture, recreation and forestry. The applicant weighted its impact factors from zero for virtually no impact, to five for maximum impact. For example, a section of proposed Route 1A was rated 5 for the factor "visual from rural dwellings" where the line would be close to rural dwellings, including the dwelling now occupied by Mr. Comeau. From this weighted matrix of 16 factors the applicant derived relative ratings for routes 1A, 1B and 2 of 107, 118, 189 respectively. On this basis the applicant saw the environmental socio-economic choice among the routes 1A, 1B and 2 as first, second and third respectively. In addition to the added impacts due to the longer line length of Route 2, this alternative would also require a new river crossing.

The applicant's estimated costs for the three routes were somewhat over three million dollars for Route 1A, somewhat under three million for Route 1B and approaching four million for Route 2. On the basis of cost alone it would have chosen Route 1B as its first choice, 1A as its second choice and Route 2 as the third choice.

Edmonton Power evaluated public concerns as a result of a public information meeting and thirteen questionaires received at that meeting, and also by considering the views of the Genesee Power Project Advisory Committee[2]. The applicant presented the combined result of consideration of these public concerns as a choice of Route 1A first, 1B second and Route 2 third.

The applicant considered the effect on system reliability of placing two 500-kV lines on a common right of way where they might be susceptible to simultaneous failure, for example, during an ice storm. The applicant said that for reliability purposes Route 2 with its separate routes might be preferrable, but also noted that 500-kV lines had already been approved on a common right of way in the Edmonton RDA near the eastern end of the approved 500-kV lines. Furthermore, Edmonton Power would use the same physical design used by TransAlta for its approved 500-kV lines.

The applicant stated that Route 2 would be first choice for reliability only and third choice with respect to other factors, including costs which would be some 30 per cent higher than Route 1. The applicant noted that Route 1A was 11 per cent more costly than Route 1B but that

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1 GPPAC is a local committee formed to provide the area with information about the Genesee project.

this route received more public support, avoided proposed wildlife habitat and was also the choice of the Genesee Power Project Advisory Committee. Furthermore, alternative 1A would be located primarily on land owned by the City of Edmonton with the exception of land owned by Propp Agencies and St. John's School. Edmonton Power is currently negotiating with both parties. In response to concerns expressed by the interveners at the hearing, Edmonton Power offered to meet outside the hearing to discuss any compensation.

## 4.2 Views of the Interveners

Mrs. Litzenberger, appearing on behalf of landowner Edward Litzenberger whose land would be adjacent to but not traversed by the applicant's preferred route 1A, stated that the owners of the land wish to retire and to sell the land as farm land but that the proposed transmission lines adjacent to the land would devalue the property, and that Edmonton Power should compensate or buy the land from Edward Litzenberger.

Mr. Comeau stated that he had sold other land to the City of Edmonton for construction of its power plant and had subsequently purchased an acreage and a dwelling from the Litzenbergers. He was of the opinion that the proposed line on the far side of the road adjacent to his property would devalue the property, and that some compensation ought to be forthcoming. He was also concerned that vegetation along the proposed right of way might be controlled by spraying with herbicides and the spray could drift onto his property. In response to this specific concern, Edmonton Power stated that it did not intend to spray along its proposed right of way.

TransAlta Utilities intervened in support of Edmonton Power's application and stated that it expected to meet the 17 March 1986 date for upgrading of the whole system to 500-kV. It did not comment on the route alternatives.

## 4.3 Views of the Examiner

The Examiner reiterates the advice in the notice of hearing, which was repeated at the public hearing itself, that matters relating exclusively to compensation are beyond the jurisdiction of the Board. Comments with respect to compensation have been included in this report because compensation appeared to be the main concern of both the Litzenbergers and Mr. Comeau; and it was noted that the applicant offered to discuss such concerns outside the hearing. If proposed alternative Route 1A were chosen, the lines would be adjacent to but would not cross the property of either the Litzenbergers or Mr. Comeau.

The proposed Alternative 1A would cross property owned by St. John's School and Propp Agencies, however, neither of these parties appeared at the hearing and the applicant confirmed it was negotiating with them.

The Examiner believes that the applicant's weighted matrix approach to impacts of the three alternative routes is a generally appropriate method of choosing among the routes. Assigning the highest impact

weighting to a factor such as "the view from adjacent rural residences" ensures that such an impact receives appropriate consideration in the process. Public concerns and preferences were also explored by the applicant prior to the hearing and generally favoured Route 1A.

In its earlier report with respect to the approved 500-kV lines, the Board commented on the reliability of this 500-kV transmission system, especially with respect to the effect on reliability of placing two lines on a common right of way. With this current proposal there could be a parallelling of lines not only at Edmonton and Keephills but now also at Genesee. The matter of the reliability of this whole 500-kV system was re-examined in the light of the current proposals. Separate consideration was given specifically to the effect on reliability of placing both proposed lines parallel to one another on a common right of way or separated on individual rights of way.

The Board's previous concerns about the effect on reliability of placing the line on a common right of way were reconfirmed. System reliability is reduced and, with this system's configuration, an overlapping outage of both circuits could occur at least once during the expected operating life of the proposed lines. The addition of the Genesee plant would not affect this situation sufficiently to preclude its interconnection to this system. However, it appears this system is approaching its limit to common cause exposure, and future parallel transmission facilities that might be proposed could be constrained by the limit of allowable common cause exposure.

Thus the Examiner believes the interconnection of the Genesee plant utilizing parallel lines on a common right of way along Route 1 is acceptable from a transmission reliability viewpoint. Furthermore, any improvement in reliability that might be gained from individual rights of way is offset in this case by the increased impact of two separate routes, an additional river crossing and about one million dollars of extra cost in comparison with Route 1.

Of the two alternative versions of Route 1, Route 1A is estimated to cost about a third of a million dollars more than Route 1B. However, the Examiner agrees that expressed public preference avoiding wetlands and a possible wildlife habitat, avoiding the lands of the Litzenbergers and Mr. Comeau, and placing most of the line route on lands already owned by the applicant counterbalance the increase in cost.

## 5 FINDINGS AND RECOMMENDATIONS

The Examiner finds that the need for the proposed facilities was previously established and has not changed in light of the present applications and evidence.

As discussed in greater detail in section 3, the proposed switching arrangement is found to be somewhat inadequate with respect to reliability,

but this could be remedied by the addition of generator unit breakers and rearrangement of the line and generator connection points within the substation.

The proposed 500-kV lines, to interconnect the Genesee substation and the already approved 500-kV lines would be of similar construction to the approved lines and are found to be suitable for their purpose. Placing two lines on a common right of way over the 5.2 kilometre route proposed would cause a noticeable but acceptable increase in the overall risk to this 500-kV system of an accident affecting both lines.

The proposed route for the two lines is somewhat more costly than the lowest cost alternative but was shown to be more acceptable in its impact, generally more favoured by the public in the area, and would be adjacent to but not across the land of interveners who appeared at the hearing. The third alternative was rejected because it was longer, would have a number of greater impacts, was less favoured by a number of local people and was considerably more costly. The Examiner finds that, all things considered, the proposed route is definitely the most acceptable choice among the three alternatives.

The Examiner therefore recommends that the Board seek the necessary Ministerial Approvals with respect to matters of the environment and then issue the appropriate approvals for the proposed 500-kV lines only.

Should the City of Edmonton choose to amend its application with respect to the configuration of the substation, the Examiner would be prepared to reconsider the technical aspects and, if satisifed with respect to reliability matters, to recommend to the Board that it approve the substation essentially as applied for in this present application together with the addition of any technical amendments applied for.

DATED at Calgary, Alberta, 18 May 1983.

C. J. Goodman

C. J. Goodman, P.Eng.

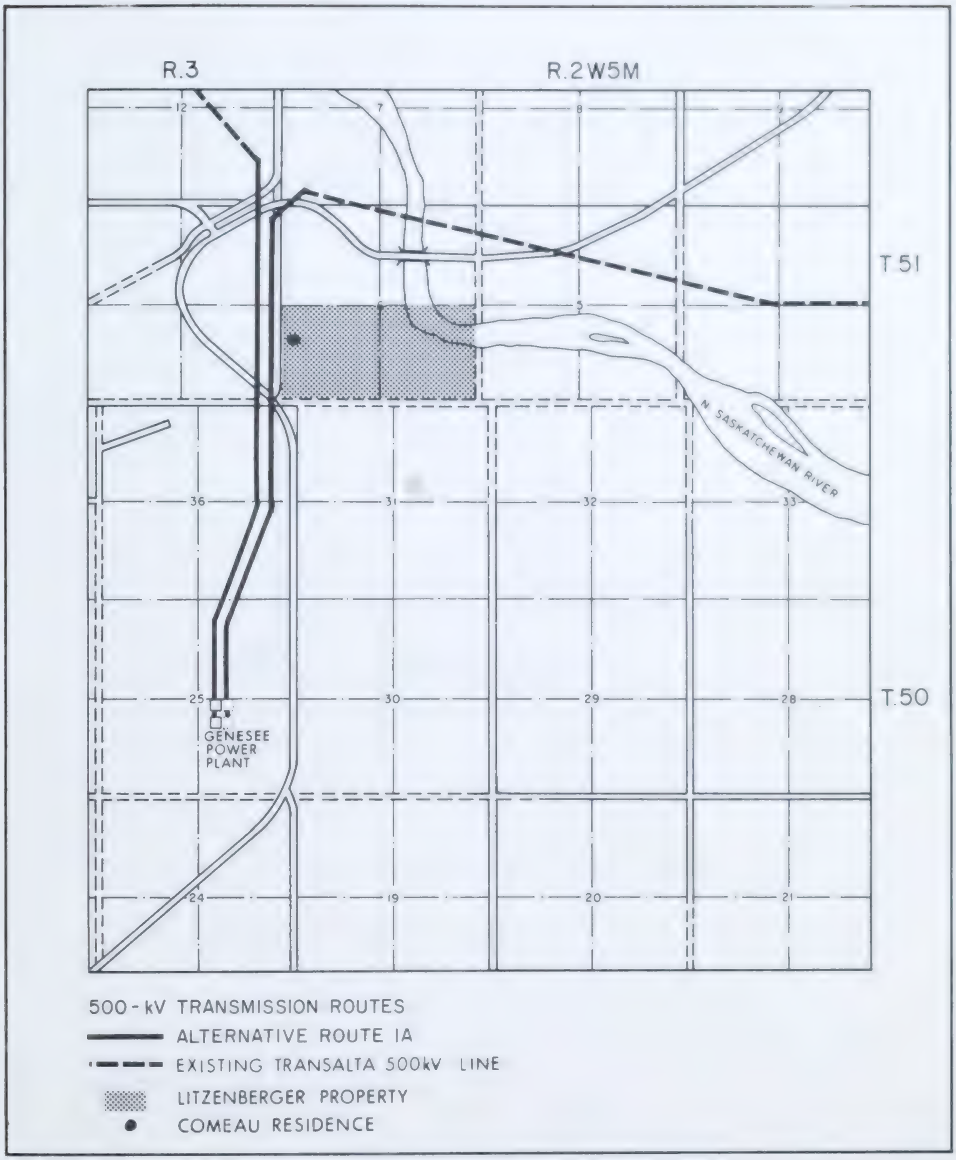



FIGURE 1 GENESEE 500kV TRANSMISSION LINES
PROPOSED ROUTE 1A

ERCB

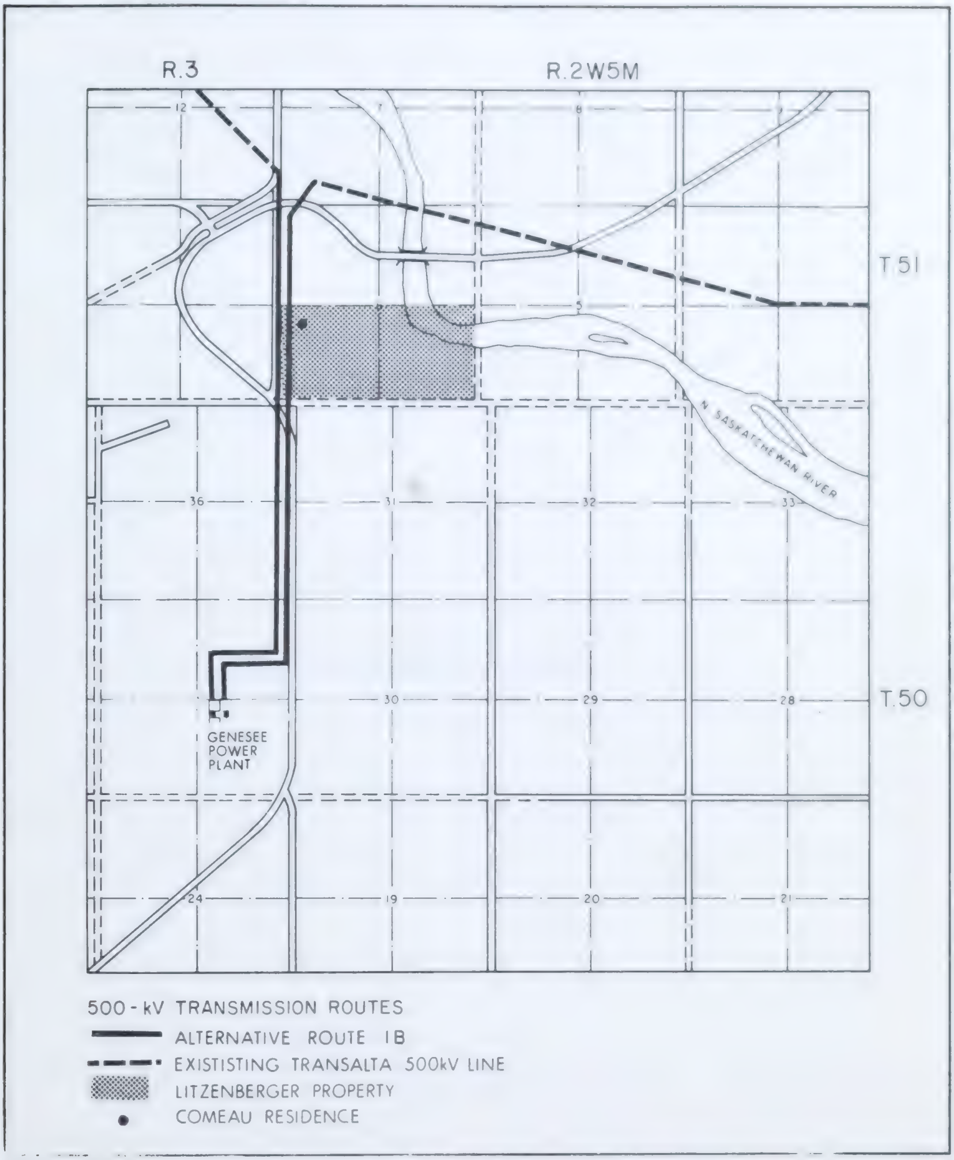



FIGURE 2 GENESEE 500kV TRANSMISSION LINES PROPOSED ROUTE 1B

ERCB

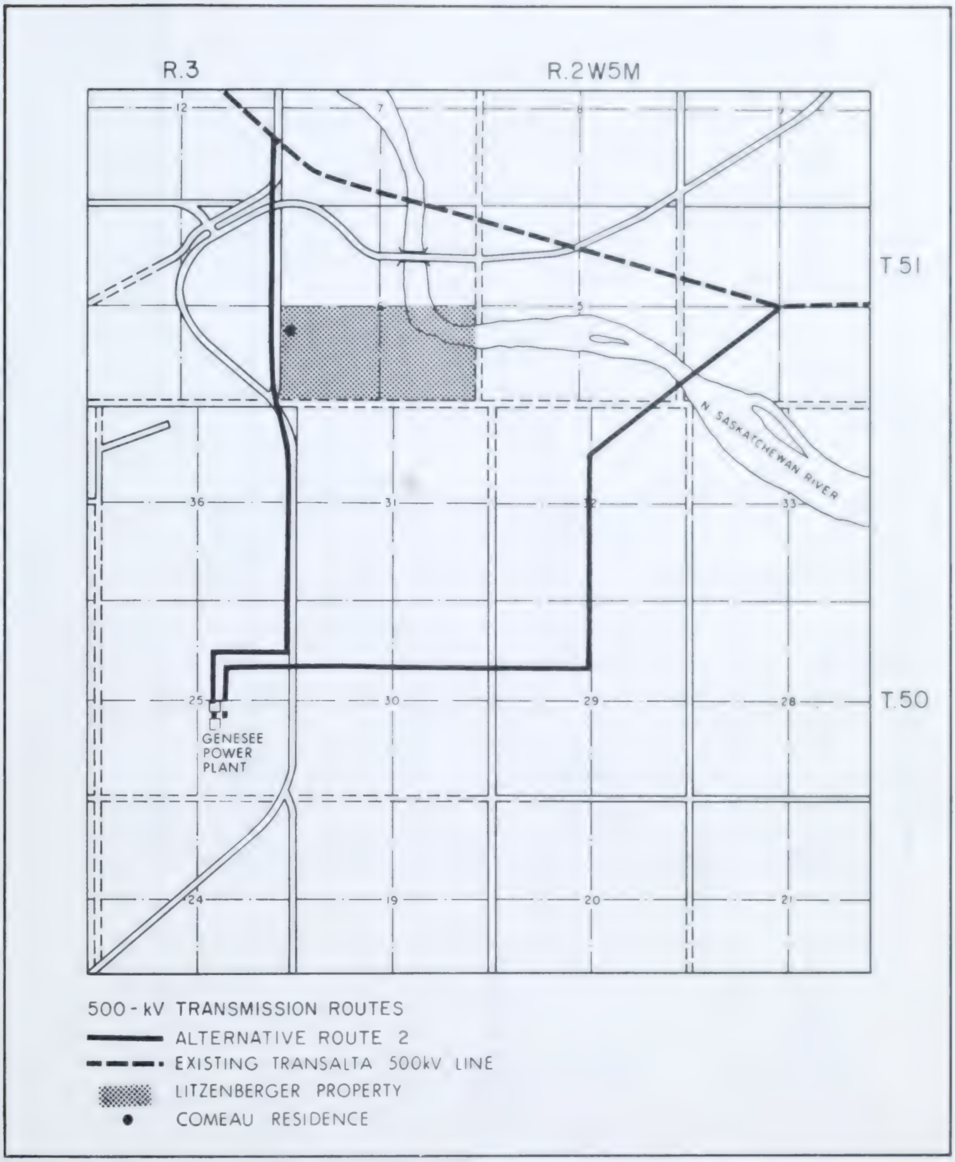



FIGURE 3 GENESEE 500kV TRANSMISSION LINES

ALTERNATIVE ROUTE 2

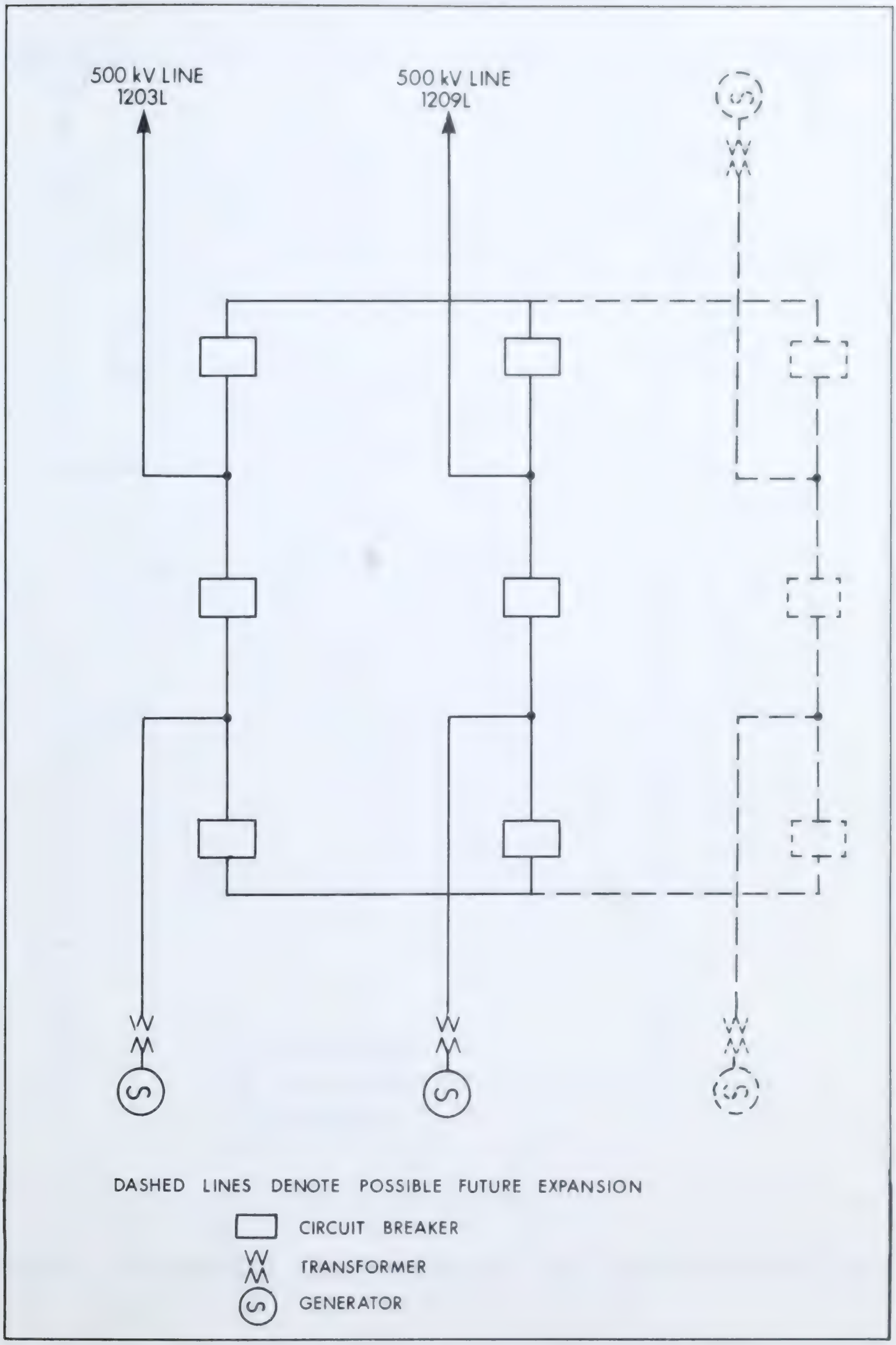



FIGURE 4 PROPOSED GENESEE SUBSTATION CONFIGURATION

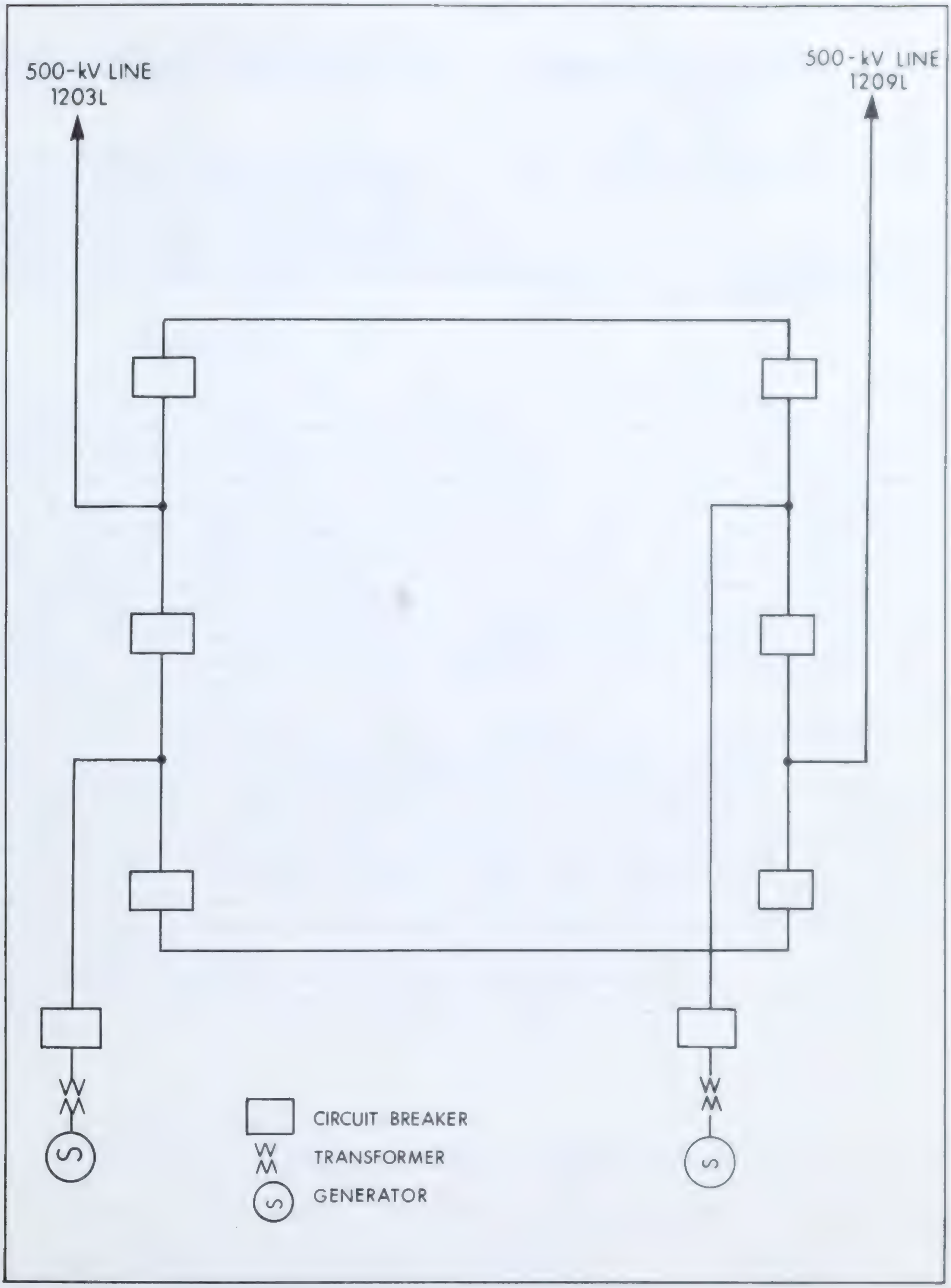



FIGURE 5 ALTERNATIVE CONFIGURATION FOR GENESEE SUBSTATION

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta



LOCAL INTERVENERS' COSTS HEARINGS
RESPECTING THE JUMPING POUND GAS
PROCESSING PLANT, THE QUIRK CREEK GAS
PROCESSING PLANT, AND THE PROPOSED
MOOSE AND WHISKEY FIELDS PIPELINE HEARINGS

Decision D 83-8

## 1 INTRODUCTION

The Board, with V. Millard, N. Strom and R. G. Evans sitting, considered at a public hearing in Calgary on December 16, 1982, and January 18, 1983, applications for awards of costs, pursuant to section 31 of the Energy Resources Conservation Act (the Act), by Zahava Hanen and Rumsey Ranches (Ms. Hanen), Andy Russell and the Canadian Wildlife Federation (Mr. Russell and C.W.F.) and R. E. Wolf (Mr. Wolf), all of whom will be collectively referred to hereinafter as "the interveners". The applications for costs were in respect of applications by Shell Canada Resources Limited (Shell) and Esso Resources Canada Limited (Esso), which were considered by the Board at public hearings on 5 to 9 October, 2 to 6 November, 23 to 27 November, 14 to 18 December 1981, 5 to 15 January 1982 and 1 February 1982.

In respect of its Jumping Pound gas processing plant, Shell applied for[1] approval to add a deep-cut unit for hydrocarbon liquid extraction and to modernize its sulphur recovery facilities. In regard to its Quirk Creek gas processing plant, Esso applied for [2] approval to utilize spare plant capacity to process sour gas reserves from the Moose and Whiskey Fields. Shell also applied for [3] permits to construct pipelines and associated facilities to gather sour gas from wells located in the Moose and Whiskey Fields and transport it to the Quirk Creek gas processing plant for processing. The applications filed by the interveners were in respect of claims for awards of costs related to their participation during the hearings.

---

1 Application No. 810092, resulting in Decision 82-3

2 Application No. 810520, resulting in Decision 82-12

3 Applications No. 810148, 810149, 810150, 810663, 810714, 810715 and 810716, resulting in ERCB Report 82-E

THOSE WHO APPEARED AT THE HEARING

| Principals (Abbreviations used in Report) | Representatives |
|---|---|
| Zahava Hanen and Rumsey Ranches (Ms. Hanen) | J. D. Rooke |
| Andy Russell and the Canadian Wildlife Federation (Mr. Russell and C.W.F.) | P. J. Madden |
| R. E. Wolf (Mr. Wolf) | S. R. Miller |
| Shell Canada Resources Limited (Shell) | D. O. Sabey, Q.C.<br>A.P.G. Walker |
| Esso Resources Canada Limited (Esso) | D. G. Hart, Q.C.<br>R. C. Pittman |
| Energy Resources Conservation Board Staff | K. F. Miller |

The summary of the claims for costs is set out in TABLE 1.

TABLE 1 SUMMARY OF CLAIMS FOR COSTS

JUMPING POUND - 810092

Claim by Ms. Hanen

| | |
|---|---|
| Solicitor's Account - Burnet, Duckworth & Palmer | |
| - Fees | 15,388.25 |
| - Disbursements | 4,142.88 |
| Consultant's Account - Edward Lewis Jones and Associates Consulting Engineers Ltd. | |
| - Fees | 15,141.83 |
| - Disbursements | 520.09 |
| TOTAL CLAIM | $35,193.05 |

Claim by Mr. Russell and C.W.F.

| | |
|---|---|
| Solicitor's Account - Schumacher, Madden & Sparling | |
| - Fees | 9,175.00 |
| - Disbursements | 4,524.68 |
| A. Russell - Expenses | 968.98* |
| TOTAL CLAIM | $ 14,668.66 |

* Mr. Russell claimed $2,906.95 for expenses for all hearings without any apportionment. The Board arbitrarily applied one-third of the cost of those expenses to each of the hearings.

Claim by R. E. Wolf

| | |
|---|---|
| Geologist Fees - R. E. Wolf | 8,456.25 |
| Consultant's Fees - Edward Lewis Jones and Associates Consulting Engineers Ltd. | 1,266.66 |
| Solicitor's Fees - Atkinson McMahon | 187.16 |
| Expenses | 40.00 |
| Travel Expenses | 30.00 |
| TOTAL CLAIM | $9,980.07 |

---

QUIRK CREEK - 810520

Claim by Ms. Hanen

| | |
|---|---|
| Solicitor's Account - Burnet, Duckworth & Palmer | |
| - Fees | 48,672.73 |
| - Disbursements | 8,603.76 |
| Consultant's Account - Edward Lewis Jones and Associates Consulting Engineers Ltd. | |
| - Fees | 14,906.83 |
| - Disbursements | 598.10 |
| Expert Witness' Accounts | |
| Dr. Farran | |
| - Fees | 570.00 |
| - Disbursements | 54.00 |

| | |
|---|---|
| Dr. Kostuch | |
| - Fees | 375.00 |
| - Disbursements | 186.20 |
| Dr. Klemm | |
| - Disbursements | 726.40* |
| Witness Fees and Expenses | |
| Zahava Hanen | 240.00** |
| Dr. Church | 250.00** |
| Fred Solterman | 1,000.00*** |
| TOTAL CLAIM | $76,183.02 |

* This amount represents claims pursuant to the Schedule; the actual expense was $661.40.

** These amounts represent claims for items set out in the Schedule although no evidence of an actual expense was submitted.

*** This amount was amended from $440.00

Claim by Mr. Russell and C.W.F.

| | |
|---|---|
| Solicitor's Account - Schumacher, Madden & Sparling | |
| - Fees | 19,887.50 |
| - Disbursements | 8,728.25 |
| Mr. Russell - Expenses | 968.98 |
| TOTAL CLAIM | $29,584.73 |

Claim by R. E. Wolf

| | |
|---|---|
| Geologist Fees - R. E. Wolf | 2,850.00 |
| Consultant's Fees - Edward Lewis Jones and Associates Consulting Engineers Ltd. | 1,579.17 |

| | |
|---|---|
| Legal Fees - Atkinson McMahon | 187.17 |
| Expenses | 40.00 |
| Travel Expenses | 41.50 |
| TOTAL CLAIM | $4,697.84 |

---

MOOSE MOUNTAIN - 810148, 810149 and 810150

Claim by Ms. Hanen

| | |
|---|---|
| Solicitor's Account - Lennie, DeBow & Martin | |
| - Fees | 1,000.00 |
| - Disbursements | 274.93 |
| Solicitor's Account - Burnet, Duckworth & Palmer | |
| - Fees | 25,845.02* |
| - Disbursements | 5,219.62* |
| Consultant's Account - Edward Lewis Jones and Associates Consulting Engineers Ltd. | |
| - Fees | 10,387.83 |
| - Disbursements | 166.76 |
| TOTAL CLAIM | $42,894.16 |

* These amounts were corrected to reflect the actual accounts. The amount claimed for fees and disbursements was only $26,799.03.

Claim by Mr. Russell and C.W.F.

| | |
|---|---|
| Solicitor's Account - Schumacher, Madden & Sparling | |
| - Fees | 11,587.50 |
| - Disbursements | 2,053.44 |
| A. Russell - Expenses | 968.98 |
| TOTAL CLAIM | $14,609.92 |

Claim by R. E. Wolf

| | |
|---|---|
| Geologist Fees - R. E. Wolf | 3,206.25 |
| Consultant's Fees - Edward Lewis Jones and Associates Consulting Engineers Ltd. | 1,266.67 |
| Legal Fees - Atkinson McMahon | 187.16 |
| - Expenses | 40.00 |
| - Travel Expenses | 40.00 |
| TOTAL CLAIM | $4,740.08 |

The Board notes that at the costs hearing Mr. Madden, representing Mr. Russell and C.W.F., raised the question of the right to recover costs related to the preparation for and attendance at the costs hearing and subsequently filed with the Board a claim in that regard.

## 2 PRELIMINARY MATTERS

### 2.1 Applicable Local Interveners' Costs Regulation

During the costs hearing counsel for Ms. Hanen and Mr. Russell raised the question as to what local interveners costs regulation should apply when the Board is making its decision in these cases. During the course of the facilities hearings and prior to the costs applications hearing, the Local Interveners' Costs Regulation, being Alberta Regulation A.R. 435/78, was in force. On December 13, 1982, the Board made a new Local Interveners' Costs Regulation A.R. 517/82, which was registered pursuant to the Regulations Act on December 15, 1982 and which appeared in the Alberta Gazette on December 31, 1982. It was

argued that because Alberta Regulation A.R. 517/82 repealed in total Alberta Regulation A.R. 435/78, the Board must make its decision in these cases pursuant to the new regulation.

The Board, after considering the arguments, and after reviewing, among others, sections 31(1) and 32(1) of the Interpretation Act, which provide, in part, respectively:

> 31(1) When an enactment is repealed in whole or in part, the repeal does not
>
> > (b) affect the previous operation of the enactment so repealed or anything done or suffered under it,
> >
> > (c) affect any right, privilege, obligation or liability acquired, accrued, accruing or incurred under the enactment so repealed, or
> >
> > (e) affect any investigation, proceeding or remedy in respect of the right, privilege, obligation, liability, penalty, forfeiture or punishment.
>
> 32(1) If an enactment is repealed and a new enactment is substituted for it,
>
> > (c) the procedure established by the new enactment shall be followed as far as it can be adapted
> >
> > > (i) in the recovery or enforcement of penalties and forfeitures incurred under the repealed enactment,
> > >
> > > (ii) in the enforcement of rights existing or accruing under the repealed enactment, and
> > >
> > > (iii) in a proceeding in relation to matters that have happened before the repeal;

has concluded that Alberta Regulation A.R. 435/78 (the Regulation) should be applied when considering these cases. The Board believes that legislation is generally not retrospective in nature, so as to affect existing rights, unless the Legislature expresses such an intention in clear and unequivocal terms.

The Board believes, however, that for purposes of its decision in these matters, its decision would be the same whether Alberta Regulation A.R. 435/78 or 517/82 is applied. The reason for that is if Regulation

435/78 is applied, and if a claim exceeds the amounts prescribed by the Schedule set out in the Regulation, the Board can only award costs in excess of the Schedule after having regard to the criteria set out in section 6(2) of that regulation. The Board believes those factors are essentially the same as the Board would consider when reviewing a claim for costs if Regulation A.R. 517/82 were applied.

## 2.2 Application Specific Versus General Matters

Prior to assessing what costs should be awarded pursuant to section 31 of the Act, and pursuant to the Regulation, the Board believes that because:

(i) it invited investigation into 100 per cent sulphur recovery or injection of waste gases in the Jumping Pound and Quirk Creek hearings,

(ii) there were wide-ranging concerns discussed at the hearings, including; sulphur dioxide emission impacts - ranging from soil acidification and livestock diseases to effects on streams and lakes; trace metal and other chemical emissions from sour gas plants; sulphur recovery at sour gas plants; and the surveillance of sour gas processing operations;

(iii) the Board was prepared to receive the evidence, even though much of it was not directly related to the specific applications, but instead related to broad environmental issues respecting sour gas operations in general, and

(iv) the Board prepared and issued ERCB Report 82-D, "Sour Gas Processing in Alberta", based on the broad and general evidence adduced at the Jumping Pound and Quirk Creek hearings,

it is fair to establish an arbitrary apportionment between application specific matters and the general matters. The Board has set out in Table 2 what it considers to be an appropriate apportionment.

When the Board attributes general matters to any specific application, the Board proposes to pay to qualifying interveners the proportion of their costs related to the general matters, insofar as those costs are considered by the Board to be reasonable. Shell and Esso will only bear liability for the reasonable costs of local interveners for the proportion of application specific matters which the Board has attributed to each respective hearing.

APPORTIONMENT
TABLE 2 APPLICATION SPECIFIC VS. GENERAL MATTERS

| | Jumping Pound | Quirk Creek | Moose Mountain |
|---|---|---|---|
| Application Specific Matters | 20% | 50% | 100% |
| General Matters | 80% | 50% | 0% |
| TOTAL | 100% | 100% | 100% |

## 3 ISSUES

Normally the Board considers claims for awards for local interveners' costs administratively by way of written submissions without any verbal argument. In this case, however, the Board believed that because of:

(1) the length of the hearings to which the costs are related,

(2) the large amounts of costs claimed by the interveners, and

(3) the complex issues related to the question of entitlement to costs by the interveners and the liability of Shell and Esso to pay the costs claimed,

it was appropriate to consider the claims for costs at a hearing where verbal submissions could be presented.

The Board believes that having regard to section 31 of the Act and to the Regulation, the issues respecting the awarding of costs in these cases are:

1. Do the interveners qualify as "local interveners" as that term is defined by section 31(1) of the Act?

2. If so, are the interveners entitled to an award of costs for the costs prescribed by the Local Interveners' Costs Schedule (the Schedule)?

3. Are the interveners entitled to an award of costs in excess of the Schedule, pursuant to section 6(2) of the Regulation?

4. What amount of costs should be awarded to the interveners for the general matters apportionment?

## 4 DO THE INTERVENERS QUALIFY AS LOCAL INTERVENERS PURSUANT TO SECTION 31(1) OF THE ACT

### 4.1 General

Section 31(1) of the Act provides:

> 31(1) In this section, "local intervener" means a person or a group or association of persons who, in the opinion of the Board,
>
> (a) has an interest in, or
>
> (b) is in actual occupation of or is entitled to occupy
>
> land that is or may be directly and adversely affected by a decision of the Board in or as a result of a proceeding before it, but, unless otherwise authorized by the Board, does not include a person or group or association of persons whose business includes the trading in or transportation or recovery of any energy resource.

It is clear that the Board's jurisdiction to award costs to a person is statutorily limited by this section. There is no inherent jurisdiction to award costs otherwise. Clearly, the Board may only award costs against an applicant in respect of a person who meets the test of a local intervener. The Board believes it has a discretion to determine who is a local intervener, but it does not have a discretion to award costs to a person if the Board does not conclude such a person is a local intervener for the subject proceeding. To do so would certainly be an act in excess of the Board's statutory jurisdiction.

## 4.2 Arguments of Ms. Hanen

Counsel for Ms. Hanen submitted that she came within the definition of "local intervener" because she was the owner of land which is or would be affected by the Jumping Pound, Quirk Creek and Moose Mountain applications. It was suggested that that was not in dispute with respect to the Quirk Creek and Moose Mountain proceedings. Concerning the Jumping Pound hearing, it was submitted that Ms. Hanen's land would be directly and adversely affected by the Jumping Pound plant because it was downwind of the plant and, in addition, the Jumping Pound plant was an alternative processing site for the Moose and Whiskey Fields gas, instead of the Quirk Creek plant.

## 4.3 Arguments of Mr. Russell and C.W.F.

Counsel for Mr. Russell submitted that the evidence indicated that Mr. Russell lived near the Quirk Creek plant, on the farm of Ms. Hanen. It was the position of Mr. Russell that "interest in land", as used in section 31(1) of the Act, should not be restricted to a legal or proprietary interest. Counsel for Mr. Russell, in any event, relied on clause (b) of section 31(1) of the Act to put forth the position that because Mr. Russell resided near the Quirk Creek plant, he therefore occupied that land, which could, it was submitted, be affected by all three applications. It was argued that Mr. Russell and C.W.F. are "local interveners".

## 4.4 Arguments of Mr. Wolf

Counsel for Mr. Wolf put forth the position that Mr. Wolf, pursuant to section 31 of the Act, is a person who has an interest in land that is or may be directly and adversely affected by the proposed operation in respect of the applied for facilities.

It was submitted that "interest in land" was not narrowly limited by the Legislature to be restricted to a financial or legal interest, but includes all interests or all concerns. Mr. Wolf's counsel suggested that Mr. Wolf had an interest in the areas surrounding the subject facilities, that being a usufructory interest. It was indicated that Mr. Wolf has had a history of fishing, hunting and hiking in the areas. It was also indicated that Mr. Wolf owns land some 32 km from the Jumping Pound plant. It was further submitted that the lands in which Mr. Wolf was interested would be affected by the gas plant emissions, which are moveable and can be widespread downwind.

4.5 Arguments of Shell

Concerning Ms. Hanen's claim respecting the Jumping Pound hearing, counsel for Shell submitted that having regard to the definition of "local intervener", there is no clear demonstration of any direct and adverse affect on her lands by the Jumping Pound plant, and there is no foundation for the Board to make an assumption that she was in fact or may in fact be directly and adversely affected. It was the position of Shell that Ms. Hanen is not a "local intervener".

Concerning Mr. Russell's and C.W.F.'s claim respecting the Jumping Pound hearing, Shell submitted there was no evidence to show that Mr. Russell had a legal right to reside at the Hanen ranch. It was further submitted that there was no evidence adduced that either Mr. Russell or C.W.F. have any interest in land at, nearby or anywhere near the Jumping Pound plant. Counsel for Shell argued that there was a lack of evidence that any land owned by anybody would be directly and adversely affected by the Jumping Pound plant.

Concerning Mr. Russell's and C.W.F.'s claim respecting the Moose Mountain hearing, Shell argued that Mr. Russell and C.W.F. are not local interveners because they had no land, they had no interest in land, and they were not in occupation of land in the sense that they had the right to direct and control the land. Shell contended that the intervention of Mr. Russell and C.W.F. was for the interest of themselves and not with respect to the lands of Ms. Hanen.

Concerning Ms. Hanen's claim respecting the Moose Mountain hearing, it was conceded by Shell that Ms. Hanen is a local intervener to the extent of her interest in grazing lease lands which would be traversed by the proposed pipeline. For lands other than the grazing lands, Shell submitted that they were not directly affected by the pipeline. Shell took the position that the real concern of Ms. Hanen was not the effect of the pipeline per se but was the indirect effect of the pipeline bringing more gas to the Quirk Creek plant.

Concerning Mr. Wolf's claim respecting both the Jumping Pound and Moose Mountain hearings, it was contended there was no evidence before the Board of an interest in land held by Mr. Wolf, and more particularly, there was no evidence by Mr. Wolf of an interest in lands which were being directly and adversely affected by the operation of the Jumping Pound plant or that would have been affected by the operation of the Moose Mountain pipeline.

4.6 Arguments of Esso

It was the position of Esso that no award of local interveners' costs can be properly made to any intervener other than Ms. Hanen. Counsel

for Esso stated that Mr. Russell and C.W.F., and Mr. Wolf, simply do not qualify for local interveners' costs as a matter of law.

Concerning C.W.F., Esso argued that it did not know of any land owned by C.W.F. which is or may be directly or adversely affected by the operation of the Quirk Creek plant.

With respect to Mr. Russell, it was submitted that any legitimate claim Mr. Russell could have to be a local intervener must be based solely on his residence at Rumsey Ranches. It was further submitted that mere residence does not amount to either:

(i) an interest in land,

(ii) actual occupation of land, or

(iii) an entitlement to occupy land.

Furthermore, it was argued that the interest in the Hanen lands adjacent to the Quirk Creek plant has been protected by Ms. Hanen.

With respect to Mr. Wolf, it was the position of Esso that Mr. Wolf was not and could never be a local intervener since there is nothing on record to indicate that he has an interest in land or is in actual occupation or entitled to occupy land which would be directly affected by the Quirk Creek plant.

4.7 Views of the Board

Obviously, the definition of "local intervener" cannot be interpreted in such a way as to say that everyone owning land in the province of Alberta, and who has a concern that a facility might directly and adversely affect his land, could intervene in a proceeding and expect to recover the costs related to the proceeding. The Board understands that it is a basic tenet of statutory interpretation that a statute must be interpreted reasonably and not in a way as to render it absurd. The Board believes that by the very existence of the definition of "local intervener" in section 31(1) of the Act the Legislature did not intend that everyone who intervenes at a Board hearing should be accorded the status of "local intervener", otherwise such an intention would have been expressed more clearly and there would not have been a need to impose the limitations evidenced by section 31(1).

In considering the definition of "local intervener", the Board believes it must examine four questions in order to attach an interpretation to that term. Those questions are:

(1) What is the meaning of "interest in land" as those words are used in section 31(1) of the Act?

(2) Under what circumstances is a person an occupant of land for purposes of section 31(1) of the Act?

(3) In order to qualify as a local intervener, can the effects for which there is a concern relate to things other than the land itself?

(4) Under what circumstances can a person allege that his land may be "directly and adversely affected", so as to qualify as a local intervener?

QUESTION (1) - "What is the meaning of "interest in land" as that expression is used in section 31(1) of the Act?

If the word "interest" were to be given its most general meaning, as was argued by the interveners, then any person might be said to have an "interest in land" for which they have a concern, although there exists no legal right in the land, such as ownership or a future right to own.

In the clearest case, a person who owns land or who has an interest in land by way of an agreement for sale can be said to have an "interest in land". At the other end of the spectrum, and where the difficulty of interpretation lies, is the case where no possessory or ownership right, whether present or future, exists. This can include temporary use of public lands, usufructory rights or temporary occupation of lands owned by another. The Board notes from section 31(1) that a person is a local intervener, assuming all other criteria can be met, if he has either an interest in or is in actual occupation of land which may be affected. The Board considers it is reasonable to draw the inference that, in enacting the definition of "local intervener", if the Legislature had intended the words "interest in land" to be given the broad meaning identified by the interveners, it would not have needed to use and indeed would not have used the words "actual occupation . . . " in the definition. The Board believes that if the Legislature had intended to confer the status of "local intervener" upon a person who was merely interested in land, then certainly the Legislature could have said just that in clear and unequivocal terms, such as:

> "In this section "local intervener" means a person or group or association of persons who, in the opinion of the Board, is interested in land that may be directly and adversely affected by a decision of the Board . . . "

The Board concludes that it was the intention of the Legislature to restrict the meaning of "interest in land" to either a present or future ownership interest in land.

QUESTION (2) - "Under what circumstances is a person an occupant of land for purposes of section 31(1) of the Act?

With respect to the second question, the Board believes that in giving a reasonable interpretation to the word "occupation", that word must be restricted to occupation or use of land, either present or future, where there is a legal right or claim to occupy or use the land. If that were not the test then, the interpretation would be so broad as to include all citizens of the province since each has a right to occupy public lands on certain occasions and under certain circumstances. As was stated in considering the interpretation of "interest in land", if the Legislature had intended that broad meaning it would surely have stated it explicitly. The Board therefore believes visitors, trespassers, sojourners, usufructory users and other persons without a legal right or claim to occupy or use the land for which there is a concern cannot be said to occupy land within the meaning of section 31(1) of the Act and would not be "local interveners". Persons who are entitled to use land, although they may not physically occupy the land for their own personal use, would include those having grazing leases, farming leases, forest management leases or other similar types of arrangements or agreements.

In summary, with respect to Questions (1) and (2), the Board does not believe it was the intention of the Legislature to give to persons who have less than an ownership interest in land or possessory right or claim in land, either for personal occupation or for uses other than occupation, the status of "local intervener" so that they might seek to recover the costs of intervention from an applicant for a facility.

If a person can satisfy all other necessary elements of the definition of "local intervener" contained in section 31(1), he would qualify as a local intervener if he:

(1) owns freehold land,

(2) has an agreement for sale in respect of land,

(3) is occupying or will be entitled to occupy land, whether Crown or freehold, providing the occupation is based on some legally enforceable right or claim,or

(4) is entitled to use land pursuant to a grazing lease, a farming lease, a forest management lease, or some other similar agreement or arrangement allowing a particular use of land over an extended period of time.

QUESTION (3) - "In order to qualify as a local intervener, can the effects for which there is a concern relate to things other than the land itself?

In considering this question, the Board must determine whether a person who owns or occupies land is a local intervener only when the land itself, may be directly and adversely affected. That is to say, if an intervener could demonstrate that a direct and adverse affect on himself might occur as the result of approval of a facility, but that his land will not be directly and adversely affected, does that mean that the landowner or occupant is not a local intervener? The Board does not believe that such an interpretation is a reasonable one. The Board believes that associated with effects on land are effects on use and enjoyment of the land. Therefore, if a person, in using his land, would suffer from health effects linked to the facility, or from noise or odour from the facility, while the land itself cannot be said to be affected, then the landowner or occupant is a local intervener for purposes of section 31(1) of the Act. A similar illustration would be the case where there would be an effect on livestock and buildings.

QUESTION (4) - "Under what circumstances can a person allege that his land may be "directly and adversely affected" in order to qualify as a local intervener?

The Board notes that a person qualifies as a local intervener if his land is directly and adversely affected, or if his land may be directly and adversely affected.

The most obvious cases where it can be shown that a person's land will be directly and adversely affected is when there will be an actual physical encumbrance caused by a facility on an individual's land, such as a pipeline, a transmission line, a well, a compressor station, or a gas plant. In cases where there will be no physical encumbrance on the land, if a person can demonstrate by evidence that his land will be otherwise directly and adversely affected by an adjacent facility, that person will qualify as a "local intervener".

In the situations where persons cannot demonstrate that land will be directly and adversely affected, they must rely on the words "may be directly and adversely affected" in order to establish their status as a "local intervener". An example of such a case is when a person claims his land may be affected by emissions from a facility although the land is located some distance from that facility. In these cases, if the intervener cannot clearly show that the land will be directly and adversely affected, then in order for him to establish his status as a "local intervener" he must satisfy the Board that the land may be directly and adversely affected. When a person asserts that land may be directly and adversely affected, the Board believes that there is a burden on such a person to demonstrate that the effect might occur. It

is simply not enough to express a concern that something might happen. On the other hand, the Board does not believe it would be reasonable to require that the effect for which there is concern be a certainty.

Where a person claims land may be directly affected, the Board would require evidence by the intervener that the basis for the concern is a reasonable one. The Board will assess the reasonableness of the concern on the strength of the evidence of the intervener in that regard, the proximity of the land to the facility, on the evidence of the potential effect, and on other matters which may be relevant. It is certainly not sufficient for interveners to simply restate widely expressed concerns which are unsupported. It is also not reasonable to raise a basis for a concern which the Board has considered before, but rejected, without introducing new evidence of the alleged potential effect which might cause the Board to reconsider its previous opinion.

## 4.8 Criteria for Establishing Status as a "Local Intervener"

Having considered the four questions, the Board believes that the issue of whether or not a person is a local intervener must be examined in light of the circumstances of each and every case; for a person may otherwise have status at a Board hearing, but not as a "local intervener", so as to entitle the person to seek local interveners' costs. The Board believes that having regard to the wording of section 31(1) of the Act, and in assessing whether a person is a local intervener, a test must be applied to determine if a person intervening in a hearing meets all the necessary elements prescribed in the definition of "local intervener". The review must be conducted with reference to the facility application to which the claim relates. In order to properly apply the test, the Board believes the following criteria must be evaluated, and in order for a person to qualify as a "local intervener", both criteria must be met:

(A) Is the intervention in respect of land which is or may be, or which the use and enjoyment of is or may be, directly and adversely affected by a decision of the Board relating to the application under consideration, and

(B) Does the person claiming costs

(i) have an ownership interest in, or

(ii) actually occupy or have a right to occupy in future,

the land which may be directly and adversely affected?

Even if a person is a "local intervener" for the recovery of costs, costs can only be awarded in respect of an application insofar as the application might affect the land or the use and enjoyment of the land for which there is concern. If an intervener chooses to pursue broad and general issues, he does so at the risk of his own expense. The Board believes it is explicit that costs can only be awarded for those portions of an intervention which deal with potential adverse affects on land or use and enjoyment of that land. The Board does not believe it has jurisdiction to impose a liability on an applicant otherwise.

4.9 Conclusions

Set out in Table 3 is the summary of conclusions of the Board in respect of Criteria (A) and (B) for each of the interveners in respect of each of the proceedings.

TABLE 3 SUMMARY OF CONCLUSIONS

| | JUMPING POUND | | QUIRK CREEK | | MOOSE MOUNTAIN | |
|---|---|---|---|---|---|---|
| Criteria | A | B | A | B | A | B |
| Ms. Hanen | No | Yes, if intervener had demonstrated a reasonable concern that such land might be directly and adversely affected | Yes | Yes | Yes | Yes |
| Mr. Russell | No | No | Yes, insofar as the Hanen lands are concerned | No | Yes | No |

| Criteria | JUMPING POUND A | JUMPING POUND B | QUIRK CREEK A | QUIRK CREEK B | MOOSE MOUNTAIN A | MOOSE MOUNTAIN B |
|---|---|---|---|---|---|---|
| C.W.F. | No | No | Yes, insofar as the Hanen lands are concerned | No | Yes, in respect of Kananaskis Country | No |
| Mr. Wolf | No | No | No | No | Yes, in respect of Kananaskis Country | No |

## 4.10 Reasons for Board Conclusions

### 4.10.1 JUMPING POUND

Ms. Hanen

Regarding Criteria (A), the Board is not satisfied that Ms. Hanen either demonstrated that her land or the use and enjoyment of her land near the Quirk Creek gas processing plant would or might be directly and adversely affected by the decision of the Board in the Jumping Pound hearing, and in any event, the approval of the application would in no way affect the lands of Ms. Hanen because the Board's decision would not approve an increase in emissions from the Jumping Pound plant nor would it extend the life of the plant by adding new fields to the plant's approval. The Board only approved a modernization of the plant in order to improve its sulphur recovery efficiency and it authorized the installation of a deep-cut facility which would enhance the recovery of resources. Following approval of the application, Ms. Hanen could not claim to be affected by the decision because, insofar as emissions were concerned, which was the subject of her concern, the total annual emissions would be decreased.

The Board does not believe that to suggest the Jumping Pound plant as an alternative to the Quirk Creek plant for the processing of Moose and Whiskey Fields gas reserves is a sufficient ground for alleging that the decision of the Board in the Jumping Pound case might directly and adversely affect the lands of Ms. Hanen. That suggestion would more properly be a matter to be considered in conjunction with the Quirk Creek plant application.

Regarding Criteria (B), it is clear from the total evidence that Hanen owns the lands for which there was a concern of effect. However, in order for a person to have the status of "local intervener" for a proceeding, both questions must be answered in the affirmative.

The Board concludes that for purposes of the Jumping Pound hearing, Ms. Hanen is not a local intervener.

Mr. Russell & C.W.F., and Mr. Wolf

Regarding Criteria (A), the Board believes that the same reasoning as applied to the Hanen intervention would apply in respect of Mr. Russell and C.W.F., and Mr. Wolf as well. Neither of these interveners demonstrated that land for which there is a concern would or might be directly and adversely affected by the Jumping Pound plant. Indeed, the Board does not believe that there could be a reasonable concern of a direct and adverse affect on any land in the Jumping Pound case when the emission levels, for which concern was expressed, would not be increased and in fact would be decreased by the decision of the Board.

Regarding Criteria (B), the Board believes that neither Mr. Russell nor C.W.F. have an interest in specific land which might be directly and adversely affected. Although Mr. Russell occupies land near the Quirk Creek plant, there was no evidence of a legal right to occupy or a possessory right in such land. Neither was there evidence that C.W.F. had some specific legal interest in any land.

Regarding Criteria (B), the Board notes that no evidence was presented by Mr. Wolf during the Jumping Pound hearing as to ownership or legal right in land which might be directly and adversely affected by the Board's decision, although the Board has concluded above that there would be no adverse affect on land arising from their decision in any case.

The Board concludes that for purposes of the Jumping Pound hearing, Mr. Russell, C.W.F. and Mr. Wolf are not local interveners.

4.10.2 QUIRK CREEK

Regarding Criteria (A), the Board believes that Ms. Hanen had, at the time of making her intervention, a reasonable concern that her land, which is adjacent to and in close proximity to the Quirk Creek plant might be directly and adversely affected by a decision of the Board in respect of the application. The application was for, among other things, the addition of fields to the plant's existing approval from which gas could be processed at the Quirk Creek plant. Approval of such an application would have had the effect of extending the economic life of the plant and its total emissions.

Regarding Criteria (B), the Board believes that the evidence adduced at the Quirk Creek hearing supports the finding that Hanen owns the lands in respect of which she intervened.

The Board concludes that, insofar as her intervention in this hearing dealt with the concern of direct and adverse effects on lands from an approval of the application, Ms. Hanen is a local intervener for the recovery of costs.

Mr. Wolf

Regarding Criteria (A), Mr. Wolf did not present any evidence of a reasonable concern that specific land might be directly and adversely affected by the decision of the Board in respect of the application. Regarding Criteria (B), there is no evidence that Mr. Wolf has a necessary legal interest in land which might be directly and adversely affected.

The Board concludes that for purposes of the Quirk Creek hearing, Mr. Wolf is not a local intervener.

Mr. Russell & C.W.F.

Regarding Criteria (A), insofar as the concerns of Mr. Russell & C.W.F. were the same as Ms. Hanen's for the Hanen land, then there was a reasonable concern that that land might be directly and adversely affected. Respecting concerns for any other lands, the Board does not believe that such concerns have been reasonably demonstrated.

Regarding Criteria (B), the Board believes that the mere residence on the Hanen lands is not a sufficient "interest in land" as prescribed by section 31(1) of the Act, nor is it "occupation", as the word is used in section 31(1), wherein the Board believes that there must be a legal right to occupy. The Board questions how someone can purport to exercise some right in respect of their occupation on land when there is no evidence in respect of the right to occupy such land. Insofar as Mr. Russell's concerns relate to the Hanen lands, which are owned by Ms. Hanen, the Board wonders why it is necessary for Mr. Russell to intervene in respect of lands for which the owner has already launched an intervention.

Insofar as the concerns of Mr. Russell & C.W.F. relate to Alberta lands in general, again the Board would note the lack of evidence to demonstrate a legal right or interest in specific lands which may be directly and adversely affected. The Board concludes that for purposes of the Quirk Creek hearing, Mr. Russell and the C.W.F. are not local interveners.

4.10.3 MOOSE MOUNTAIN

Ms. Hanen

Regarding Criteria (A), the Board believes that Ms. Hanen's grazing lease lands would be directly and adversely affected by the applied for pipeline, since the line would traverse part of that land. Regarding Criteria (B), the evidence is clear and there is no dispute that Ms. Hanen holds grazing leases to the lands which would be affected.

Respecting Ms. Hanen's freehold lands, the Board believes that the use and enjoyment of those lands would be directly and adversely affected by the proposed pipeline because of the proximity of the pipeline, being a sour gas line, to those lands.

The Board concludes that for the purposes of the Moose Mountain hearing, Ms. Hanen is a local intervener for the recovery of costs.

Mr. Russell & C.W.F.

Regarding Criteria (A), the evidence is clear that Mr. Russell and C.W.F. had a reasonable concern respecting land which might be directly and adversely affected by the proposed construction of the pipeline, that is, Kananaskis Country area. However, regarding Criteria (B), the general interest of Mr. Russell and C.W.F. in the Kananaskis Country is not sufficient to meet the test of "interest in land" or occupation of land for the purpose of section 31(1) of the Act.

The Board concludes that for purposes of the Moose Mountain hearing, Mr. Russell and the Canadian Wildlife Federation are not local interveners.

Mr. Wolf

Regarding Criteria (A), the comments respecting Mr. Russell and the C.W.F. in the Moose Mountain application are essentially applicable. Furthermore, the concern respecting earthquakes, terrorism and the Calgary water supply were not such that the Board would conclude that, other than for the Kananaskis Country, Mr. Wolf had a reasonable concern for specific land which might be directly and adversely affected by the application.

Regarding Criteria (B), Mr. Wolf's concern for the Kananaskis Country and the usufructory interest claimed in that land is not sufficient to meet the test of "interest in land" or occupation of land as the Board believes it should be interpreted.

The Board concludes that for purposes of the Moose Mountain hearing, Mr. Wolf is not a local intervener.

## 5 WHAT COSTS SHOULD BE AWARDED PURSUANT TO THE SCHEDULE AND BY WAY OF A DISCRETIONARY AWARD?

### 5.1 General

Having regard to the Board's findings respecting "local intervener" status and bearing in mind that the question of reasonableness of costs claimed, in the context of section 6 of the Regulation, has yet to be assessed, the Board has set out in Table 4, a summary of eligibility of the interveners for the recovery of costs for either the application specific matters or the general matters apportioned by the Board.

TABLE 4 ELIGIBILITY FOR AWARD

| | Jumping Pound | | Quirk Creek | | Moose Mountain |
|---|---|---|---|---|---|
| | 20% Appl. Specific Matters | 80% General Matters | 50% Appl. Specific Matters | 50% General Matters | 100% Application Specific Matters |
| Hanen | No | Yes | Yes | Yes | Yes |
| Russell and C.W.F. | No | Yes | No | Yes | No |
| Wolf | No | Yes | No | Yes | No |

Having answered issue number 1, the Board will, in the case of Hanen, who is the only intervener for which Shell and Esso might be ordered to pay costs, review her costs and address issues number 2 and 3, being:

> 2. Is Hanen entitled to an award of costs pursuant to the Schedule?
>
> 3. Is Hanen entitled to an award of costs in excess of the Schedule, pursuant to section 6(2) of the Regulation?

5.2 Arguments Respecting What Amounts of Costs Should be Awarded to Ms. Hanen - Quirk Creek and Moose Mountain Application Specific Matters

5.2.1 Ms. Hanen

Counsel for Ms. Hanen argued that his client was in need of legal and technical assistance for both hearings. It was submitted that the costs were actually incurred, they were not excessive and were directly and reasonably related to the hearings.

It was argued that awarding of costs pursuant to the Schedule would not be adequate. Counsel for Hanen submitted that the Board should exercise its discretion pursuant to section 6(2) of the Regulation because all criteria of that section had been satisfied. The Board was requested to allow all costs claimed.

5.2.2 Esso in Respect of Quirk Creek

Counsel summarized the position of Esso that Ms. Hanen's claim ought to be confined to the amounts contained in the Schedule and for only those portions which related to site specific matters. He characterized most of the evidence adduced on behalf of Ms. Hanen as not being relevant or site specific to the Quirk Creek plant. It was the submission of Esso that a discretionary award should not be made because the three criteria contained in section 6(2) of the Regulation had not been satisfied.

5.2.3 Shell in Respect of Moose Mountain

Counsel for Shell conceded that Ms. Hanen is a local intervener insofar as her grazing lease lands would have been traversed by the proposed pipeline and to the extent that those lands would be affected. With respect to her other lands, he suggested that they would not be affected, and indeed Ms. Hanen did not adduce any evidence concerning potential effects to those lands. It was the position of Shell that costs should not be awarded, but if they are, they should not exceed one-half the amounts allowed by the Schedule and that, in any case, no discretionary award should be made.

5.3 Costs to be Awarded to Hanen

In Table 5 the Board has set out the costs which Ms. Hanen is awarded:

(i) pursuant to the Schedule, and

(ii) by way of discretionary awards, pursuant to section 6(2) of the Regulation, for that portion of the costs being in excess of the amounts prescribed by the Schedule.

With respect to Quirk Creek, the Board has calculated a total award of costs as if all of the interventions related to application specific

matters, however, Esso would be responsible for only 50 per cent of the total costs awarded, being the percentage apportioned to application specific matters.

TABLE 5 COSTS AWARDED TO MS HANEN FOR APPLICATION SPECIFIC MATTERS - QUIRK CREEK AND MOOSE MOUNTAIN

QUIRK CREEK

| Item | Amount Claimed | Amount Awarded Pursuant to Schedule | Amount of Disecretion-ary Award | Total Award for Each Item |
|---|---|---|---|---|
| Solicitor's Fees | 48,672.73 | | 41,172.73 | |
| 1 (a) Preparation - maximum 2 days x $500.00 | | 1,000.00 | | |
| (b) Attendance at hearing - 13 days x $500.00 | | 6,500.00 | | |
| 3 (a) Transcripts | 5,948.50 | 5,948.50 | | |
| (b) Disbursements | 2,655.26 | 2,655.26 | | |
| | $57,276.49 | $16,103.76 | $41,172.73 | $57,276.49 |

| Item | Amount Claimed | Amount Awarded Pursuant to Schedule | Amount of Discretion-ary Award | Total Award for Each Item |
|---|---|---|---|---|
| Consultant's Fees | 14,906.83 | | 12,806.83 | |
| 2 (c)(i) Briefing with solicitor | | 150.00 | | |
| (c)(ii) Attendance at hearing 13 days x $150.00 | | 1,950.00 | | |
| 3 (b) Disbursements | 598.10 | 598.10 | | |
| | $15,504.93 | $2,698.10 | $12,806.83 | $15,504.93 |
| Dr. Farran's Fees | 570.00 | | 270.00 | |
| 2 (c)(i) Briefing with solicitor | | 150.00 | | |
| (c)(ii) Attendance at hearing 1 day x $150.00 | | 150.00 | | |
| (d)(i) travel expenses | 54.00 | 54.00 | | |
| | $624.00 | $354.00 | $270.00 | $624.00 |

| Item | Amount Claimed | Amount Awarded Pursuant to Schedule | Amount of Discretionary Award | Total Award for Each Item |
|---|---|---|---|---|
| Dr. Kostuch's Fees | 375.00 | | 75.00 | |
| 2 (c)(i) Briefing with solicitor | | 150.00 | | |
| (c)(ii) Attendance at hearing 1 day x 150.00 | | 150.00 | | |
| 2 (d)(i) travel expenses | 78.20 | 78.20 | | |
| (d)(ii) meals and accommodation | 108.00 | 108.00 | | |
| | $561.20 | $486.20 | $75.00 | $561.20 |
| Dr. Klemm's Fees | 335.00 | | | |
| 2 (c)(i) Briefing with solicitor | | 150.00 | | |
| (c)(ii) Attendance at hearing 1 1/2 days x $150.00 | | 225.00 | | |
| 2 (d)(i) travel expenses | 125.00 | 125.00 | | |
| (d)(ii) meals and accommodation | 201.40 | 201.40 | | |
| | $661.40 | $701.40 | - | $701.40 |

| Item | Amount Claimed | Amount Awarded Pursuant to Schedule | Amount of Discretionary Award | Total Award for Each Item |
|---|---|---|---|---|
| Ms. Hanen | | | | |
| 2 (a) Briefing with solicitor | 50.00 | 50.00 | | |
| (b) Attendance at hearing - 1 1/2 days x $50.00 | 75.00 | 75.00 | | |
| 2 (d)(i) travel expenses | 90.00 | 90.00 | | |
| (d)(ii) meals and accommodation | 25.00 | 25.00 | | |
| | 240.00 | 240.00 | - | $240.00 |
| Dr. Church | | | | |
| 2 (c) Witness Fees | $25.00* | | | |
| (c)(i) Briefing with solicitor | 150.00 | 150.00 | | |
| (c)(ii) Attendance at hearing 1/2 day x $150.00 | 75.00 | 75.00 | | |
| | $250.00 | $225.00 | - | $225.00 |

* This portion of claim disallowed because the witness fee for an expert witness is included in Item 2(c)(ii) of the Schedule.

| Item | Amount Claimed | Amount Awarded Pursuant to Schedule | Amount of Discretionary Award | Total Award for Each Item |
|---|---|---|---|---|
| Mr. Solterman - expenses | 340.00 | | | |
| 2 (a) Briefing with solicitor | | 50.00 | | |
| (b) Attendance at hearing - 1 day x $50.00 | | 50.00 | | |
| 2 (d)(i) travel expenses | 560.00* | 168.00** | | |
| (d)(ii) meals and accommodation | 100.00 | 100.00 | | |
| | $1,000.00 | $368.00 | - | $368.00 |

* Mileage claimed at .50 per kilometre.
** Mileage allowed at .15 per kilometre.

| | | | | |
|---|---|---|---|---|
| TOTAL CLAIM | $76,118.02 | | | |
| TOTAL AWARD PURSUANT TO SCHEDULE | | $21,176.46 | | |
| TOTAL DISCRETIONARY AWARD | | | $54,324.56 | |
| TOTAL AWARD | | | | $75,501.02 |
| COSTS FOR WHICH ESSO IS LIABLE TO MS. HANEN $75,501.02 x 50% | | | | $37,750.51 |

MOOSE MOUNTAIN

| Item | Amount Claimed | Amount Awarded Pursuant to Schedule | Amount of Discretionary Award | Total Award for Each Item |
|---|---|---|---|---|
| Solicitor's Fees - Burnet Duckworth & Palmer | 25,845.02 | | 19,095.02 | |
| 1 (a) Preparation - maximum 2 days x $500.00 | | 1,000.00 | | |
| (b) Attendance at hearing - 11 1/2 days x $500.00 | | 5,750.00 | | |
| 3 (a) Transcripts | 4,581.00 | 4,581.00 | | |
| (b) Disbursements | 638.62 | 638.62 | | |
| | $31,064.64 | $11,969.62 | $19,095.02 | $31,064.64 |
| Solicitor's Fees - Lennie, DeBow & Martin | 1,000.00 | | 1,000.00 | |
| 3 (b) Disbursements | 274.93 | 274.93 | | |
| | $1,274.93 | $274.93 | $1,000.00 | $1,274.93 |
| Consultant's Fees | 10,387.83 | | 8,587.83 | |
| 2 (c)(i) Briefing with solicitor | | 150.00 | | |
| (c)(ii) Attendance at hearing 11 days x $150.00 | | 1650.00 | | |

| Item | Amount Claimed | Amount Awarded Pursuant to Schedule | Amount of Discretionary Award | Total Award for Each Item |
|---|---|---|---|---|
| 3 (b) Disbursements | 166.76 | 166.76 | | |
| | $10,554.59 | $1,966.76 | $8,587.83 | $10,554.59 |
| TOTAL AMOUNT CLAIMED | $42,894.16 | | | |
| TOTAL AWARD PURSUANT TO SCHEDULE | | $14,211.31 | | |
| TOTAL DISCRETIONARY AWARD | | | $28,682.85 | |
| TOTAL AWARD | | | | $42,894.16 |
| COSTS FOR WHICH SHELL IS LIABLE TO MS. HANEN | | | | $42,894.16 |

The awards made pursuant to the Schedule against Shell and Esso reflect those items and amounts which are consistent with the Schedule and which, in the opinion of the Board, are directly and necessarily related to the preparation for and participation in the Quirk Creek and Moose Mountain hearings on behalf of Ms. Hanen.

The Board, after having regard to the amount of her claims and the costs she is entitled to recover pursuant to the Schedule, believes it is appropriate to make a discretionary award in respect of both hearings. In making the discretionary awards the Board has had regard to its jurisdiction under section 6 of the Regulation which states:

> 6 (1) If the Board awards costs or a portion or share of costs to a local intervener, the portion or share of costs determined by the Board shall not exceed for any matter the costs prescribed in the Schedule.

(2) Notwithstanding subsection (1), if the Board in a particular proceeding, having regard to

(a) the need of the local intervener and the parties to the proceeding,

(b) the nature and complexity of the proceeding and intervention, and

(c) the economics of the conduct of the proceeding or intervention,

considers that the amount of costs prescribed in the Schedule would not be appropriate in awarding costs or a portion or share of costs to a local intervener in that proceeding, the Board may vary from the amount of costs prescribed in the Schedule.

and in particular section 6(2). The Board has made the following findings:

(i) that Ms. Hanen was in need of assistance in preparation and presentation of her interventions in both hearings,

(ii) the Board believes both applications to be of a nature and sufficient complexity so as to require the intervener to retain the services of a solicitor and experts, and

(iii) insofar as the Board has allowed costs by way of a discretionary award in each proceeding against Shell and Esso, the economics of the conduct in each proceeding by Ms. Hanen was reasonable and necessary.

The Board has allowed some of the expenses of Mr. Solterman, pursuant to the Schedule. On the day Mr. Solterman appeared to give his evidence, the Board ruled that some of his evidence was not relevant to the Quirk Creek hearing and accordingly, struck out portions of his filed submission. Following the ruling, Mr. Solterman was withdrawn as a witness. The Board believes it is appropriate that the expenses of Mr. Solterman which are within the Schedule should be awarded since he did appear at the hearing to give evidence although, ultimately, no evidence was tendered.

## 7 WHAT COSTS SHOULD BE AWARDED FOR GENERAL MATTERS

The Board, having apportioned general matters to the Jumping Pound and Quirk Creek applications at 80% and 50% respectively, is prepared to pay to each intervener his or her costs attributed to such matters to the extent the Board considers those costs reasonable.

The Board having reviewed the amount of costs apportioned for each intervener to general matters and the nature of the cost, believes the costs set out in Table 6, column 3, are reasonable and should be paid to each intervener by the Board.

TABLE 6 COSTS AWARDED FOR GENERAL MATTERS

Jumping Pound

| | Total Amount Claimed | 80% of Total Claim | Costs Awarded for General Matters |
|---|---|---|---|
| Ms. Hanen | $35,193.05 | $28,154.44 | $28,154.44 |
| Mr. Russell & C.W.F. | $14,668.66 | $11,734.93 | $11,734.93 |
| Mr. Wolf | $ 9,980.07 | $ 7,984.06 | $ 1,276.50 |

Quirk Creek

| | Total Amount Claimed | 50% of Total Claim | Costs Awarded for General Matters |
|---|---|---|---|
| Ms. Hanen | $76,183.02 | $38,091.51 | $38,091.51 |
| Mr. Russell & C.W.F. | $29,584.73 | $14,792.36 | $14,792.36 |
| Mr. Wolf | $ 4,697.84 | $ 2,348.92 | $ 1,676.50 |

With respect to Mr. Wolf, the Board has allowed $1,276.50 of his claim apportioned to the Jumping Pound general matters and $1,676.50 of his claim apportionted to the Quirk Creek general matters. The Board has made its award to compensate Mr. Wolf for his legal fees and for his mileage, typing and photocopying expenses. The Board has also made a general general award to Mr. Wolf of $100.00 per day for his attendance at the Jumping Pound and Quirk Creek hearings. The Board derived the $100.00 per day figure from its policy set out in ERCB Guide G-31, "Guidelines Respecting Applications for Local Interveners' Costs Awards".

The Board has disallowed Mr. Wolf's claim for his fees in respect to his attendance at the hearings at the rate of $75.00 per hour and for the fees of engineering consultants. The Board does not believe it is reasonable for a person to claim an hourly rate for their attendance at a hearing, unless they can demonstrate an actual out of pocket expense and there was a need to be present for the full hearing, particularly in the case of an extended hearing such as applies to these applications. It is also not reasonable to claim costs related to work of engineering consultants, when the consultants are not presented as witnesses on behalf of the interveners claiming the costs or the need for the advice is not demonstrated.

## 8 COSTS RELATED TO ATTENDANCE AT COSTS HEARING

Concerning the request of Mr. Madden that the interveners' costs relted to the preparation for and attendance at the costs hearing be awarded, the Board's is prepared to pay those costs, and claims in that regard should be directed to the Board.

## 9 DECISION

1. In respect of the Jumping Pound hearing, the Board will pay to Ms. Hanen $28,154.44 for costs incurred and related to the general matters apportionment.

2. In respect of the Jumping Pound hearing, the Board will pay to Mr. Russell and C.W.F. $11,734.93 for costs incurred and related to the general matters apportionment.

3. In respect of the Jumping Pound hearing, the Board will pay to Mr. Wolf $1,276.50 for costs incurred and related to the general matters apportionment.

4. In respect of the Quirk Creek hearing, Ms. Hanen is awarded $37,750.51 local interveners' costs, pursuant to section 31 of the Act.

5. In respect of the Quirk Creek hearing, the Board will pay to Ms. Hanen $38,091.51 for costs incurred and related to the general matters apportionment.

6. In respect of the Quirk Creek hearing, the Board will pay to Mr. Russell and C.W.F. $14,792.36 for costs incurred and related to the general matters apportionment.

7. In respect of the Quirk Creek hearing, the Board will pay to Mr. Wolf $1,676.50 for costs incurred and related to the general matters apportionment.

8. In respect of the Moose Mountain hearing, Ms. Hanen is awarded $42,894.16 local interveners' costs, pursuant to section 31 of the Act.

9. Except as otherwise awarded herein, the Board denies the other portions of the claims.

DATED at Calgary, Alberta on 30 June 1983.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

N. Strom, P.Eng.
Board Member

R. G. Evans, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

LOCAL INTERVENERS' COSTS HEARINGS
RESPECTING THE RAM RIVER GAS PROCESSING PLANT
AND THE STRACHAN GAS PROCESSING PLANT HEARINGS — Decision D 83-9

## 1 INTRODUCTION

The Board, with V. Millard, N. Strom, P.Eng. and R. G. Evans, P.Eng. sitting, considered at a public hearing in Calgary on January 18, 1983, applications for an award of costs, pursuant to section 31 of the Energy Resources Conservation Act (the Act), by Dr. Martha Kostuch and her company, the Rocky Veterinary Clinic Ltd. (Dr. Kostuch). The applications for costs were in respect of applications by Canterra Energy Ltd. (Canterra) and Gulf Canada Resources Inc. (Gulf), which were considered by the Board at public hearings on 26 and 27 April 1982 and on 3 to 6 May 1982.

In respect of the Ram River gas processing plant, Canterra applied for[1] approval to process additional sour gas reserves at the plant. In regard to its Strachan gas processing plant Gulf applied for[2] approval to process additional sour gas reserves at the plant, to restore and maintain throughput. The applications filed by Dr. Kostuch were in respect of claims for awards of costs related to her participation during the hearings.

THOSE WHO APPEARED AT THE HEARING

| Principals (Abbreviations used in Report) | Representatives |
|---|---|
| Dr. Martha Kostuch and Rocky Veterinary Clinic Ltd. (Dr. Kostuch) | R. D. Schachter |
| Canterra Energy Ltd. (Canterra) | F. M. Saville |
| Gulf Canada Resources Inc. (Gulf) | J. D. Anderson |
| Energy Resources Conservation Board Staff | K. F. Miller |

1 Application No. 810650, resulting in Decision 82-15

2 Application No. 810849, resulting in Decision 82-15

The summary of the claims for costs is set out in Table 1.

TABLE 1 SUMMARY OF CLAIMS FOR COSTS BY DR. KOSTUCH

| | Canterra | Gulf |
|---|---|---|
| Legal Fees | 13,868.00 | 6,837.00 |
| Legal Disbursements | 845.53 | 372.97 |
| Dr. Kostuch's Expenses | 783.00 | 391.88 |
| Dr. Chaudry's Account | 1,479.50 | 739.50 |
| Dr. Shaffer's Account | 477.71 | 238.85 |
| TOTAL | $17,453.74 | $8,580.20 |

## 2 ISSUES

Normally the Board considers claims for awards for local interveners' costs administratively by way of written submissions without any verbal argument. In this case, however, the Board believed that because of the complex issues related to the question of entitlement to costs by Dr. Kostuch and the liability of Canterra and Gulf to pay the costs claimed, it was appropriate to consider the claims for costs at a hearing where verbal submissions could be presented.

The Board believes that having regard to section 31 of the Act and to the Local Interveners' Costs Regulation, being A.R. 435/78 (the Regulation), the issues respecting the awarding of costs in these cases are:

1. Does Dr. Kostuch qualify as a "local intervener", as that term is defined by section 31(1) of the Act?

2. If so, is Dr. Kostuch entitled to an award of costs for the costs prescribed by the Local Interveners' Costs Schedule (the Schedule)?

3. If so, is Dr. Kostuch entitled to an award of costs in excess of the Schedule, pursuant to section 6(2) of the Regulation?

## 3 DOES DR. KOSTUCH QUALIFY AS A LOCAL INTERVENER PURSUANT TO SECTION 31(1) OF THE ACT?

### 3.1 General

Section 31(1) of the Act provides:

> "31(1) In this section, "local intervener" means a person or a group or association of persons who, in the opinion of the Board,
>
> (a) has an interest in, or
>
> (b) is in actual occupation of or is entitled to occupy
>
> land that is or may be directly and adversely affected by a decision of the Board in or as a result of a proceeding before it, but, unless otherwise authorized by the Board, does not include a person or group or association of persons whose business includes the trading in or transportation or recovery of any energy resource."

It is clear that the Board's jurisdiction to award costs to a person is statutorily limited by this section. There is no inherent jurisdiction to award costs otherwise. Clearly, the Board may only award costs against an applicant in respect of a person who meets the test of a local intervener. The Board believes it has a discretion to determine who is a local intervener, but it does not have a discretion to award costs to a person if the Board does not conclude such a person is a local intervener for the subject proceeding. To do so would certainly be an act in excess of the Board's statutory jurisdiction.

### 3.2 Arguments of Dr. Kostuch

It was argued by counsel for Dr. Kostuch that Dr. Kostuch and her company had due cause to be concerned with respect to sulphur dioxide emissions from the Canterra and Gulf plants and that before the hearing, when Dr. Kostuch had to formulate her opinion about intervening, she had due cause to be concerned that there would be a direct and adverse effect on her land.

Counsel submitted that the evidence, both before and during the hearing, would lead Dr. Kostuch to believe that sulphur dioxide emissions would fall on her land and that they would cause harm to the land. It was the position put forth on behalf of Dr. Kostuch that insufficient research has been done on sulphur dioxide emissions to be confident that land, in the proximity that Dr. Kostuch's land is to the Canterra plant, would not be directly and adversely affected by the emissions.

In response to the suggestion that Dr. Kostuch's intervention was based on general concerns as opposed to specific concerns related to her lands, counsel for Dr. Kostuch said that the private concern and the public concern are one and the same, for if all other land around Dr. Kostuch's land were directly and adversely affected, then her lands would be as well.

### 3.3 Arguments of Canterra

Counsel for Canterra submitted that in order for the Board to say Dr. Kostuch is a local intervener, it must be satisfied that she is an owner or has an interest in or is an occupant of land and there has to be some connection to the land. Secondly, it was submitted that the Board must also be satisfied that the land is directly and adversely affected by the decision of the Board in respect of the application. Counsel contended that the question of whether an effect is direct and adverse is a decision for the Board, not a subjective thing on the part of the person who chooses to intervene in a proceeding. Canterra took the position that there was no evidence before the Board that there had been any impact on Dr. Kostuch's land from the Canterra plant. Canterra submitted that Dr. Kostuch is not a local intervener.

### 3.4 Arguments of Gulf

Gulf argued that it believed it was questionable whether there is a direct and adverse effect on the lands of Dr. Kostuch, and accordingly, whether she qualified as a local intervener.

### 3.5 Views of the Board

With respect to the interpretation of the definition of "local intervener" contained in section 31 of the Act, the Board has reviewed and fully adopts its views expressed in Section 4.7 of Decision Report D 83-8, relating to local interveners' costs applications for the Jumping Pound, Quirk Creek and Moose Mountain hearings.

### 3.6 Criteria for Establishing Status as a "Local Intervener"

The Board has reviewed its comments contained in section 4.8 of the Jumping Pound, Quirk Creek and Moose Mountain costs decision and believes them to apply fully.

Accordingly, the Board will apply the two criteria test to determine if Dr. Kostuch has met all the necessary elements prescribed in the definition of "local intervener". Those criteria are:

> (A) Is the intervention in respect of land which is or may be, or which the use and enjoyment of is or may be, directly and adversely affected by a decision of the Board relating to the application under consideration, and
>
> (B) Does the person claiming costs
>
> > (i) have an ownership interest in, or

(ii) actually occupy or have a right to occupy in future,

the land which may be directly and adversely affected?

### 3.7 Conclusions

Set out in Table 2 is the summary of conclusions of the Board in respect of Criteria (A) and (B) in respect of each proceeding.

TABLE 2 SUMMARY OF CONCLUSIONS

| Proceeding | Criteria A | Criteria B |
|---|---|---|
| Ram River | No | Yes, if Dr. Kostuch had demonstrated a reasonable concern that such land might be directly and adversely affected. |
| Strachan | No | Yes, if Dr. Kostuch had demonstrated a reasonable concern that such land might be directly and adversely affected. |

### 3.8 Reasons for Board Conclusions

In the case of both plant applications, the Board is not satisfied that Dr. Kostuch demonstrated either her land or the use and enjoyment of her land would or might be directly and adversely affected by the decision of the Board.

Although the Board does not believe the distance that land is from a source of emissions is the determining factor as to whether or not a person can reasonably allege that his or her land might be directly and adversely affected by the emissions, it is nonetheless one factor that must be taken into account.

As was stated in the Jumping Pound, Quirk Creek and Moose Mountain costs decision, an intervener claiming to have status as a local intervener need not demonstrate that the adverse effect for which there is a concern will occur, but the intervener must lead evidence to show that the concern, in light of the circumstances of that particular case, is a reasonable one. Dr. Kostuch's land is some 35 km from the Canterra plant and 25 km from the Gulf plant. Each of these plants had been in operation for about 10 years and have been emitting sulphur dioxide to the atmosphere at rates which for many years exceeded the emissions expected from approval of the application. Dr. Kostuch did not present any evidence that her lands or the use or enjoyment of them had in any way been affected by the plant operations to date nor did she identify how and why they might be affected in the future. The Board, having regard to the evidence adduced by Dr. Kostuch at the plant hearings, cannot conclude that the concern was sufficiently justified to meet the test.

There is no dispute that Dr. Kostuch was an owner of the land which she alleged would be directly and adversely affected by the gas plants.

The Board concludes that, for the purposes of both hearings, Dr. Kostuch is not a "local intervener", pursuant to section 31(1) of the Act.

## 4 WHAT COSTS SHOULD BE AWARDED

### 4.1 General

The Board, having concluded that Dr. Kostuch is not a local intervener, has no jurisdiction to award costs against Canterra and Gulf. Accordingly, there is no need to consider issues 2 and 3.

### 4.2 Payment of Costs by Board

Notwithstanding Dr. Kostuch's lack of status as a "local intervener", the Board believes it is appropriate to compensate Dr. Kostuch for 50% of the total costs incurred in relation to these proceedings. The Board is prepared to do so because at the time Dr. Kostuch intervened, the Board's decision respecting Jumping Pound, Quirk Creek and Moose Mountain costs was not available. That decision represents the first detailed review by the Board of the definition of "local intervener", and how the Board interprets that term.

If Dr. Kostuch had had the opportunity to consider the Board's analysis of who may or may not be a "local intervener" she could have been said to have had notice of the Board's interpretation. That, however, was

not the case. Because of these particular circumstances, the Board is willing to compensate Dr. Kostuch, in part. In future cases, the Board will expect prospective interveners, who are uncertain as to their status as a "local intervener" to have full regard to the Jumping Pound, Quirk Creek and Moose Mountain costs decision.

The Board notes that Gulf has made a voluntary payment to Dr. Kostuch in the sum of $5,594.04.

### 4.3 Costs for Attendance at Costs Hearing

Counsel for Dr. Kostuch asked the Board to consider making an award in respect of counsel's fees and disbursements related to preparing for and attending the costs hearing. Because of the unusual circumstances of conducting the costs hearing, the Board believes such an award is appropriate and is prepared to pay the costs as filed with the Board.

### 4.4 Interest on Award

Counsel for Dr. Kostuch submitted that because of the period of time intervening between the gas plant hearings and the Board's consideration of costs, it would be appropriate to allow interest on costs awarded. Once again, in these special circumstances, the Board believes, because of the length of time it took to arrive at a decision in these costs matters, it is appropriate to allow interest on the 50% of Dr. Kostuch's costs which the Board is prepared to pay. Accordingly, interest at the rate of 14% is allowed on $13,016.97 from July 15, 1982, (reflecting a reasonable time interval by which costs should be determined in most cases) to the date of this decision.

## 5 DECISION

1. In respect of the Ram River and Strachan gas plant hearings, the Board will pay to Dr. Kostuch $13,016.97 for costs incurred in relation to those hearings.

2. The Board will pay to Dr. Kostuch costs related to legal fees and disbursements for her counsel's attendance at the costs hearing.

3. The Board will pay to Dr. Kostuch $1,746.50, representing interest on $13,016.97 calculated at 14.0% from July 15, 1982 to June 30, 1983.

4. The claims for costs by Dr. Kostuch are otherwise denied.

DATED at Calgary, Alberta on 30 June 1983.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

N. Strom, P.Eng.
Board Member

R. G. Evans, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

VOYAGER PETROLEUMS LTD. AND
SIGNALTA RESOURCES LIMITED
SOUR GAS PROCESSING IN EAST-CENTRAL ALBERTA

Decision D 83-10
Applications 821089
830012 & 830087

TABLE OF CONTENTS

# 1 INTRODUCTION

## 1.1 Voyager Petroleums Ltd. Application No. 821089

Voyager Petroleums Ltd. (Voyager) applied, pursuant to section 26 of the Oil and Gas Conservation Act, for approval to construct and operate sour gas processing facilities at its well located in Lsd 4-26-41-16 W4M (4-26 well). The facilities would be designed to process a maximum of 56.4 thousand cubic metres per day (56.4 x $10^3$ $m^3/d$) of sour gas containing 33.8 $m^3$ of hydrogen sulphide ($H_2S$) from which 54.0 x $10^3$ $m^3/d$ of sweet gas would be recovered and transported to the Signalta-Heisler gas processing plant for further processing. A maximum of 0.092 tonnes per day (t/d) of sulphur dioxide ($SO_2$) would be emitted to the atmosphere from a 12.2 metre (m) flare stack.

## 1.2 Signalta Resources Limited Application No. 830012

Signalta Resources Limited (Signalta) applied, pursuant to section 26 of the Oil and Gas Conservation Act, for approval to expand its existing Heisler gas plant located in Lsd 13-14-42-16 W4M, and to install amine sweetening facilities. The plant is presently licensed to process 225 x $10^3$ $m^3/d$ of raw sweet gas from which 224 x $10^3$ $m^3$ of sales gas and 1.2 $m^3$ of pentanes plus are recovered. The expanded plant would process a maximum of 368.5 x $10^3$ $m^3/d$ of sour gas containing 1.8 x $10^3$ $m^3$ of $H_2S$, from which 346.3 x $10^3$ $m^3$ of sales gas and 1.4 $m^3$ of pentanes plus would be recovered. A maximum of 5.0 t/d of $SO_2$ would be emitted to the atmosphere from a 38.0-m flare stack.

## 1.3 Signalta Resources Limited Application No. 830087

Signalta Resources Limited applied, pursuant to section 26 of the Oil and Gas Conservation Act, for approval to construct and operate an iron sponge sweetening unit at its well located in Lsd 10-31-42-15 W4M (10-31 well). The facilities would process a maximum of 14.09 x $10^3$ $m^3/d$ of sour gas containing 11.3 $m^3$ of $H_2S$ from which 14.08 x $10^3$ $m^3$ of sweet gas would be recovered and transported to the Signalta-Heisler gas plant for further processing. Approximately 0.015 t/d of sulphur would be removed by the iron sponge sweetening unit and under normal operating conditions, no sulphur or sulphur compounds would be emitted to the atmosphere. The sulphur in the gas would collect on the iron sponge which would be disposed of at a suitable landfill site when it became saturated.

## 1.4 Reasons for One Hearing and Decision Report

The Board believes that the applications are closely related in that they all affect the same gas gathering system, the two single-well proposals are located within 8 kilometres (km) of the central facility (see Figure 1) and gas from the wells would be delivered to the

central facility for further processing. Also, in a meeting at the Hastings Coulee Hall held prior to the hearing, it became evident that local residents were opposed to any proliferation of plants in the east central part of the province. Therefore, in order to assess the impact of the applied-for facilities on residents in the area, but recognizing the interrelationship of the facilities, the Board decided to hear the applications consecutively at one hearing and deal with all of them in this report.

### 1.5 Hearing

The hearing of the applications took place on 29 and 30 March 1983 in Heisler, Alberta, with G. J. DeSorcy, P.Eng., C. J. Goodman, P.Eng., and E. J. Morin, P.Eng., sitting. The following table lists the participants at the hearing.

## 2 ISSUES

The Board considers the issues with respect to each of the applications to be:

- need for the proposed facilities,
- impacts and relative desirability of the proposal and alternatives, and
- special conditions of operation if the proposal is approved.

THOSE WHO APPEARED AT THE HEARING

| Principals and Representatives (Abbreviations used in Report) | Witnesses |
|---|---|
| Voyager Petroleums Ltd. (Voyager) J. Schlegel | J. Goemans, P.Eng. of Voyager Petroleums Ltd. D. Padula, P.Eng. of Swinarton Engineering Ltd. |
| Signalta Resources Limited (Signalta) J. B. McCashin | J. Stueck, P.Eng. E. Dhenin both of Signalta Resources Limited D. Widynowski, P.Eng. of Widy Engineering Ltd. |

THOSE WHO APPEARED AT THE HEARING (cont'd)

| Principals and Representatives (Abbreviations used in Report) | Witnesses |
|---|---|
| East Central Landholders Protective Assoc. (Protective Assoc.)<br>E. Waite | E. Waite |
| Hastings Coulee Community (Community)<br>W. Henderson | W. Henderson |
| Warren Henderson Family (W. Henderson) | W. Henderson |
| Robert Coulthard Family (R. Coulthard) | B. Coulthard<br>V. Coates |
| Einar and Rhoda Fossen | |
| Art Hihn Family (A. Hihn)<br>F. Hihn | M. Hihn<br>A. Hihn |
| Colin and Barbara Kroetsch<br>R. Kroetsch | C. Kroetsch<br>R. Kroetsch |
| The Town of Daysland<br>R. Damberger | |
| The Village of Forestburg<br>C. Farvolden | |
| Forestburg Veterinary Clinic | |
| Aberan Angus Farm (R. Tate) | R. Tate |
| The Crown<br>S. L. Dobko of Alberta Environment | |
| Energy Resources Conservation Board staff<br>M. J. Bruni<br>E. P. Moeller, C.E.T.<br>L. S. Fillion, C.E.T. | |

## 3 NEED FOR THE PROPOSED FACILITIES - APPLICATIONS 821089, 830012, AND 830087

### 3.1 Views of Voyager

The applicant stated that the 4-26 well had been completed and flow tested in May 1982. Limited field testing of the well at that time indicated that there was no $H_2S$ present in the gas stream. Subsequently, construction of a sweet gas pipeline to tie the well into the Signalta-Heisler plant was completed in June 1982. The well was brought on stream in early July and produced for approximately 17 hours. Voyager stated that the well was shut-in at 10:00 a.m. on 7 July 1982, as it was suspected of being responsible for the gas produced from the Heisler plant containing concentrations of $H_2S$ in excess of the limit of 16 parts per million (ppm) for sales gas. The concentration of $H_2S$ at the 4-26 well was then measured, and determined to be 370 ppm. Further testing of the well in August 1982 measured an average $H_2S$ concentration of 580 ppm.

Voyager said that it had been aware that Signalta was planning to apply for the installation of gas sweetening facilities at the Heisler gas plant. The applicant stated that initially it applied to the Board for the installation of a temporary amine sweetening unit at the 4-26 well because it was under the impression that once sweetening facilities had been installed at the Heisler plant, Voyager would be able to discontinue the use of its wellhead sweetening unit, and produce the 4-26 well directly to the Heisler plant.

However, in subsequent discussions with the Board's Pipeline Department, Voyager was informed that the pipeline which tied the 4-26 well into the Heisler gas plant was not suitable for transporting gas containing even such relatively small amounts of $H_2S$ (see section 9.6 of this report). Therefore, Voyager concluded that if it were to produce the 4-26 well, sweetening would have to take place at the wellhead and it had then requested that the Board consider its application as one for a permanent installation.

### Views of Signalta

Signalta testified that the Heisler plant has been in operation for three years and is processing gas from 10 wells. However, the 10-31 well, and the 4-26 well owned by Voyager, produce sour gas with $H_2S$ concentrations well in excess of the 16 ppm maximum for sales gas.

Signalta stated that the 10-31 well had been drilled as a sweet gas well, and since the majority of wells in the area are sweet, Signalta felt confident in building a sweet gas pipeline to tie the 10-31 well into the existing gathering system. The applicant stated that the well had been on production for two days when the presence of $H_2S$ was

detected. At that time, the well was tested and the $H_2S$ concentration measured between 120 and 130 ppm. Later, the well was flow tested for approximately one week and the $H_2S$ concentration had stabilized at 800 ppm.

The applicant stated that in the recent past other wells in the system had turned slightly sour, the concentration of $H_2S$ in the gas being just over the 16 ppm level. Further, Signalta wished to tie-in 11 new wells which varied in $H_2S$ concentration up to a maximum of 1.0 per cent (10 000 ppm). Although the existing gathering system was licensed for sweet gas service only, Signalta stated that the proposed 11-well gathering system would be built to sour gas specifications. The applicant stated that its proposed amine sweetening unit was necessary because its gas must be processed in order to be saleable.

### 3.2 Views of the Interveners

Although the majority of the interveners did not question the need for any of the facilities, R. Kroetsch stated that since there is presently a surplus of gas in the province, it was not really necessary for the applicants to produce their gas.

### 3.3 Views of the Board

The Board notes that the applicants have leased mineral rights, drilled and completed wells capable of producing natural gas, and have obtained the necessary approvals to produce the gas. In designing for the production of certain wells in the area, the applicants did not adequately anticipate the presence of $H_2S$ and consequently, production of some wells had to be halted when the presence of $H_2S$ was detected.

The Board believes that the applicants have the right to produce their gas reserves subject to the pertinent regulations, standards, and guidelines. Since production of their reserves, as they exist, would violate the various regulations, the Board sees a need to modify or add to the facilities already in existence, in order to allow the applicants to resume production of their gas and to allow recovery of an Alberta resource to continue. The Board therefore concludes that, providing that the impact of such facilities would not be unacceptable, there is a need for gas sweetening facilities in the area, either on site or at a central location.

The Board has analysed, in section 9.1 of this report, the feasibility of transporting the sour gas to a possible central sulphur recovery plant designed to handle all the sour gas in the area. The analysis has led the Board to the conclusion that such a scheme would not be practical.

THE VOYAGER APPLICATION 821089

# 4 IMPACT AND RELATIVE DESIRABILITY OF THE PROPOSAL AND ALTERNATIVES

## 4.1 Views of Voyager

The applicant testified that the proposed amine gas sweetening plant would be skid mounted, housed in a metal building, and totally enclosed by a chain link fence. Voyager stated that the facility would be equipped with a 12.2-m flare stack designed to maintain the ground level concentration of $SO_2$ below the Clean Air Act guideline of 0.17 ppm. Voyager noted that on average over a year, the $SO_2$ would be emitted at a rate that was only 50 to 60 per cent of the rate applied for, due to market conditions for the gas produced.

Voyager stated that its proposed unit had been greatly modified and simplified from a typical amine sweetening unit but that it would still be as reliable, although somewhat less flexible, when compared with conventional systems. Voyager was confident that its proposed unit would be capable of sweetening the gas efficiently and safely, in conformance with all government regulations and requirements.

Voyager discussed the various safety features of the plant, which would include automatic shutdown valves on the plant inlet and outlet gas lines and safety relief valves connected to flow into the flare stack and to prevent overpressuring of the process vessels. The flare stack would be equipped with a gas pilot and an automatic ignition system to ensure the complete combustion of any vented gases. Additionally, Voyager stated that the plant would be attended during the day.

Voyager said that its proposed plant had been designed to comply with all of the standards and requirements of the Board and Alberta Environment. The standards and requirements had been established in order to protect the public, ensure environmental quality, and provide for the safe and efficient operation of all gas processing facilities.

Voyager stated that its plant would be one of the smallest in Alberta and that it did not expect any adverse health effects or complaints as a result of its operations. However, it stated that it would be willing to investigate any complaints. Additionally, Voyager offered to install corrosion monitoring stations, and to install a mobile $SO_2$ monitoring trailer for a one-month period, the first time a complaint was received.

With respect to the possibility of expanding the plant in the future, Voyager stated that its gas contract restricted it to producing a maximum of $56.4 \times 10^3$ $m^3/d$ of gas from its reserves underlying the 4-26 well. Furthermore, it could not foresee the gas contract being increased. The applicant did indicate that an offset well might be drilled sometime in the future in an effort to maintain the throughput of the plant as the output of the existing well declined. Voyager emphasized that, even if a second well were tied in, the throughput and emission rates established for the plant would remain the same as applied for and no additional impact would result.

Voyager stated that the alternatives to the installation of an amine unit at the 4-26 site were: installation of an iron sponge unit, or construction of a new pipeline between the well and the Heisler gas plant. Although the iron sponge process would not result in $SO_2$ emissions to the air, it would produce a solid waste by-product. Voyager estimated that, if such a unit were installed, the spent sponge material would have to be disposed of about every four months. The spent sponge and its associated acidic waters would have to be neutralized and then trucked to the County of Flagstaff landfill site.

Voyager also stated that the iron sponge process would not remove unwanted carbon dioxide ($CO_2$) from the gas and was not recommended for use when the concentration of $H_2S$ and the volume of gas to be sweetened were as large as in this case. Further, the capital cost of a suitable iron sponge unit would be approximately \$400 000.

The applicant testified that the pipeline which ties the 4-26 well into the Heisler plant could not be upgraded to allow transportation of sour gas. Replacement of the pipeline would cost in the order of \$275 000, and processing the sour gas at the Heisler plant could involve an additional \$200 000 in order to buy a share of the Signalta plant, as compared with the \$208 000 capital cost for the proposed unit.

Burying a new pipeline would result in additional surface disturbance over its entire 8-km length and would necessitate the transportation of sour gas over a longer distance.

Voyager emphasized that there was no production history for the pool that the well is drilled into and it is difficult to predict how the well will perform. A new pipeline would have no salvage value and would therefore represent an added economic risk if the 4-26 well did not turn out to be a good producer. Alternatively, if the proposed well-site sweetening unit were installed but the well did not perform as expected, it could be salvaged and used for some other application.

Neither of the alternatives would result in the creation of an additional emission source. Voyager agreed that, in general, it would be better to have a single large $SO_2$ emission source as opposed to a number of small sources with the same cumulative emission volume, but indicated that in this instance the additional emission source was justified. The applicant pointed out that had the pipeline connecting the 4-26 well to the Heisler plant been suitable for transporting sour gas, Voyager would not have applied for a well-site sweetening unit.

4.2 Views of the Interveners

The interveners generally expressed concern that emissions from the plant would have an adverse effect on certain individuals in the area who have known health problems. They suggested that anything which would impact on the health of people, should not be allowed.

R. Coulthard stated that the applicant should be required to prove that its proposed facilities would not cause odours, health problems, or property damage. He further stated that certain types of health damage are irreversible and an investigation of any damage after the fact would be of no benefit to the affected individuals. He stated that he was not in favour of installing gas sweetening facilities at the 4-26 site unless there were no atmospheric emissions.

R. Kroetsch stated that Voyager should be required to transport its gas to the Heisler plant for processing.

The Protective Assoc. was concerned that, if additional wells were tied into the plant at some future date, operating problems would increase and the community would be subjected to an increasing risk. It also expressed concern that emissions from the plant would cause acidic precipitation which would result in property damage.

The interveners generally indicated that they were not as concerned with gas processing facilities which performed as intended as they were with the effects when operating problems developed. They suggested that once a facility was in place, and should problems arise, they would have great difficulty in getting corrective action initiated. V. Coates on behalf of R. Coulthard, related the problems he had encountered over a three-year period when a gas sweetening plant near his home did not operate properly. The interveners feared that they would experience similar problems. (The Board has addressed the comments of V. Coates in section 9.2.)

4.3 Views of the Board

The Board, in attempting to compare the available alternatives to that proposed by Voyager, has concluded that it does not have sufficient information to adequately evaluate the alternative of sweetening by an iron sponge process. In particular, the Board is not certain that it

fully understands the details of the cost estimate given by Voyager for such a unit, or the additional costs which might be necessary at the central gas processing facility, if an iron sponge unit was installed. The Board also requires additional information as to whether the $CO_2$ problem referred to by Voyager, would be a serious one which would preclude the sale of gas if an iron sponge process was used rather than the proposed amine unit. Finally, the Board is not satisfied that Voyager had fully evaluated and properly compared the environmental impacts that would result from the use of an iron sponge unit as compared to those that would occur if the proposal was approved.

The Board has requested additional information of the applicant in a letter dated 14 June 1983, copies of which have been sent to all participants in the hearing. The Board is deferring its decision with respect to the Voyager application until after the requested information has been received and evaluated.

Its findings and decision will be issued as an addendum to this report.

## THE SIGNALTA APPLICATION 830012

## 5 IMPACT AND RELATIVE DESIRABILITY OF THE PROPOSAL AND ALTERNATIVES

### 5.1 Views of Signalta

Signalta stated that the 38-m flare stack, to be installed at its modified plant, had been designed to maintain the ground level concentration of $SO_2$ below the ambient air quality standard of 0.17 ppm. Signalta pointed out that, although it was requesting approval to process a maximum of $368.5 \times 10^3$ $m^3/d$ of raw gas and to emit up to 5.0 t/d of $SO_2$, the plant would normally operate at about 50 to 60 per cent of its maximum capacity. Additionally, the concentration of $H_2S$ in the inlet gas stream is expected to be about half of the 0.5 per cent used in designing the plant modification. Therefore, Signalta estimated that the combined effect would result in an emission rate of about one quarter of the rate applied for.

Signalta stated that it did not expect that the gas which it would produce would get significantly more sour over time. The applicant submitted that it had designed the amine sweetening facilities with a 50 per cent margin so that the plant would be able to handle any fluctuations in the $H_2S$ concentration of the gas, or the gas from any additional sour wells drilled to maintain the throughput of the plant as production from the existing wells begins to decline. Signalta

stated that, unless there is a major gas discovery in the area, it did not foresee any need to have the $SO_2$ emission rate increased above the requested 5.0 t/d.

Signalta stated that it would keep track of the $H_2S$ concentration in the gas by monthly gas analysis supplemented by daily Draeger tube measurements. The applicant stated that the Draeger tube measurements were reasonably accurate and would be adequate to determine if there were significant changes in the $H_2S$ concentration of the gas.

Signalta described the various safety features of the plant which included automatic shutdown valves on the plant inlet and outlet gas lines, an alarm system to detect the presence of $H_2S$ or combustible gases in the process buildings, and an automatic system for alerting the operator by telephone in the event of an alarm or shut-down. The applicant stated that the plant would be attended 8 hours per day and, for the remaining 16 hours, an operator would be on call.

Signalta stated that the flare stack would be equipped with an automatic ignition system that would be integrated into the plant alarm system such that the operator would be notified in the event that the flare went out. Signalta indicated that it planned to use a newer type of flare ignition system that required a minimum of fuel gas and was easy to light and maintain. The applicant also indicated that it would utilize a closed flare system to ensure that any $H_2S$ vapours from sour water or hydrocarbon liquids would be flared to prevent odours.

The applicant explained that, with the exception of the amine unit, the plant would remain essentially the same as it is now. Therefore, Signalta stated that it did not expect that the operation of the plant would result in any complaints about noise or smoke since none had been received to date. Signalta also stated that it would restore ditch lines and pipeline right of ways as close to the original condition as was possible.

In response to the interveners request that the new facilities be relocated on less productive farmland to the north of the plant site, Signalta maintained that the proposed layout was the most logical for several reasons and that a relocation would create a number of construction and operating problems. For example, it would result in a much longer acid gas line from the amine unit to the flare stack. Signalta submitted that because of the high concentration of $H_2S$ in the acid gas (16 per cent), and because of its corrosive properties, the acid gas line should be kept as short as possible.

One of the alternatives to the proposed method of processing would be to transport the Signalta gas to an existing sour gas plant. However, Signalta explained that any of the existing sour gas plants would have to be expanded to accommodate the increased volume of gas.

Thus, the impacts associated with gas sweetening operations would not be avoided, but merely transferred to another location. Further, Signalta estimated that it would cost approximately $750 000 more to build the necessary pipeline and field facilities than to take the gas to the Heisler plant. This gathering system would result in additional surface disturbance and would possibly have to cross the Battle River. Also, there would be other risks associated with transporting the sour gas over long distances.

The applicant stated that because the $H_2S$ concentration of the gas in the east central part of the province is relatively small, a very large number of wells would be required in order to have available the volume of gas and amount of $H_2S$ needed to justify the building of a sulphur recovery plant. Signalta stated that it did not believe that the reserves in the area were enough to support such a project.

Transporting all the sour gas reserves in the area to a central sulphur recovery plant would cause extensive surface disturbance and would require a vast network of pipelines. Signalta pointed out that a sulphur recovery facility would also introduce an entirely different set of potential impacts ranging from sulphur storage and transportation problems to sulphur dusting. Signalta concluded that the impacts associated with sulphur recovery at a central facility would be much greater than those associated with its proposal.

With respect to sulphur recovery, Signalta estimated that the capital cost of a Claus unit would be in the order of $1-1.4 million and although sulphur recovery was technically possible, it was not economically feasible.

Finally, Signalta stated that the only other alternative would be to shut-in its gas. The applicant contended that it would be in the greater public interest for it to produce its reserves.

The applicant submitted that its proposed scheme would have a positive economic impact on the community by providing tax revenue and job opportunities. Signalta stated that its proposed scheme was the best alternative because the facilities would be constructed at an existing plant, the surrounding area is very flat, and there are no large bodies of water in the vicinity. Further, there is only one residence within 1.6 km of the plant. Signalta concluded that from an engineering, operating, and safety standpoint, its proposed scheme is far superior to any other alternatives.

## 5.2 Views of the Interveners

W. Henderson, and A. Hihn who owns the land on which the plant is located, both expressed concern that the proposed facilities would take productive farmland out of operation. A. Hihn requested that every effort be made to locate the proposed facilities to the north of

the existing plant and as far away from his buildings as possible. W. Henderson wanted to ensure that Signalta would replace the topsoil and restore the land disturbed when pipelines were built.

W. Henderson questioned whether the operator of the plant would be able to respond quickly in an emergency situation in case of adverse weather conditions. He also inquired about the back-up procedures that had been established if the operator was unable to get to the plant or to a well site.

W. Henderson remarked that some veterinarians contend that the presence of sulphur in forage may lead to selenium deficiency diseases in cattle.

C. Kroetsch stated that he was worried about the effect of $SO_2$ emissions on the health of his daughter who has allergies.

R. Kroetsch stated the most efficient plants in the province from an environmental standpoint were the ones which recovered sulphur. He contended that, since there is an excess of natural gas in the province and therefore no need for Signalta to produce its gas reserves, Signalta should not be allowed to contaminate the atmosphere with $SO_2$ emissions. R. Kroetsch recommended that if Signalta were allowed to process sour gas, it should be required to install sulphur recovery facilities at its plant.

R. Kroetsch stated that the Shell-Rosevear gas plant which does recover sulphur emits less $SO_2$ than would Signalta's proposed plant, and is equipped with a 375-foot (114-m) flare stack. He did not believe that Signalta's proposed 38-m flare stack would be adequate, and recommended that Signalta install a taller flare stack in order to dissipate the $SO_2$ to a greater extent.

## 5.3 Views of the Board

The Board believes that the flare stack at the proposed facility has been adequately designed to provide for the dispersion of the maximum possible emission rate of 5.0 t/d of $SO_2$ and to maintain the ground level concentration of $SO_2$ below 0.17 ppm. The Board notes that the $SO_2$ emission rate would normally be much less than the 5.0 t/d applied for. The Board has addressed R. Kroetsch's concerns in sections 9.3 and 9.4 of this report.

The Board is satisfied that the proposed plant would employ up-to-date technology with respect to the automatic ignition device and that the closed flare system would reduce the likelihood of nuisance odours caused by $H_2S$ leaks. Further, proper operation of the plant should not result in incidents of black smoke emissions that might cause concern among area residents.

The Board notes that the proposed facility would not incorporate any noise producing equipment so there should be no increase in the noise levels currently experienced at or near the plant.

With respect to processing Signalta's gas at an existing sour gas plant, the Board notes that the gas would have to be transported over a longer distance and any impacts associated with processing, however small, would simply be transferred to another location. Also, the Board believes that this alternative would not be the most cost effective. The applicant proposes to utilize an existing gas plant and gathering system where some land disturbance has already occurred and further disturbance would be minimized.

The Board agrees that the proposed layout of facilities at the plant site would be satisfactory and that relocation of the facilities to the north of the site would pose potential construction and operating problems. However, the Board notes Signalta's intention to discuss the matter further with A. Hihn and to accommodate his views to the maximum practical extent. Signalta also gave a commitment to restore ditch lines and pipeline right of ways to as close to the original condition as possible.

The Board agrees with Signalta that the installation of sulphur recovery facilities at the Heisler plant, to recover 2.5 t/d of sulphur (5.0 t/d $SO_2$) cannot be justified from an economic standpoint and thus should not be required unless the emissions from the plant would result in impacts that are unacceptable. Additionally, the Board believes that the low tonnage of sulphur in the inlet gas stream and fluctuating markets for the sales gas would cause numerous technical and operating problems at a sulphur recovery plant since these facilities tend to be relatively inflexible and highly sensitive to changes in throughput.

The Board has investigated the potential for sulphur recovery in the east-central part of the province and its findings are discussed in section 9.1 of this report. It has concluded that a sulphur recovery facility would not be practical.

With respect to public health and environmental effects, the Board believes that the proposed plant has been designed to meet all existing safety and pollution standards and that such standards do incorporate a safety factor based on the effects of $SO_2$ on human health. Further, the Board notes that operators of sour gas plants are required to monitor the ambient air and soil pH in the vicinity of the plant. Such monitoring will provide the data necessary to evaluate the impact of the plant and will indicate if any remedial measures are required. Having regard for the level of emissions and the operating history of similar and substantially larger sour gas processing plants, the Board believes that adequate safeguards will exist with regard to air quality and human health.

The Board also notes that Signalta's proposed scheme would provide some increased tax revenue and job opportunities.

Having regard for the need for sweetening facilities in the area, the alternatives available, and the fact that the proposed facilities are designed to meet all standards and would have a low level of impacts on residents, the Board is prepared to approve the application.

## 6 SPECIAL CONDITIONS OF OPERATION

### 6.1 Views of Signalta

Signalta stated that it would be required to institute an air monitoring program as a condition of operation. The applicant proposed to maintain four static exposure cylinders for the detection of $H_2S$ and for measuring total sulphation, and an air monitoring trailer for two months per year. Signalta indicated that the trailer would contain equipment for the continuous monitoring of $H_2S$ and $SO_2$ and also measure wind speed and direction. Signalta stated that it would be prepared to maintain the trailer for longer periods of time if necessary. The applicant offered to make the results of all monitoring available to anyone who was interested.

Signalta stated that it would consider installing a telephone alarm at the Hihn residence so that the family would be aware of emergency situations that occurred at the plant. It also stated that it would be prepared to provide A. Hihn, who has worked previously with the plant operator, with some training in shutdown procedures and to further discuss with him the location of the proposed facilities.

The applicant testified it would be installing emergency shutdown valves at the well sites for each of the sour gas wells proposed to be tied into the plant. Also, Signalta stated that it would consider installing similar devices at any of the existing slightly sour wells if odour complaints were received.

Signalta agreed to organize a meeting with the local people to further explain the design and operation of the proposed facilities.

### 6.2 Views of the Interveners

A. Hihn made a request, which was supported by W. Henderson, to have a telephone installed in his home and for training in shutdown procedures for the plant.

The interveners favoured Signalta's intention to hold an information meeting but suggested that in future such meetings should be held before a project reached the stage where a public hearing became

necessary. W. Henderson suggested that all applicants for new or expanded gas processing plants should arrange to meet with local people prior to asking them to sign consent or release forms.

### 6.3 Views of the Board

The Board notes that sour gas plants are required to monitor ambient air quality as well as soil pH. Additionally, the Board has its own monitoring equipment which can be used if complaints are received or if problems are expected.

The Board supports Signalta's intention to hold an information meeting with local residents and would make Board staff available to attend such a meeting if so requested. With respect to communications between energy developers and the public, the Board has made some more general comments in section 9.5 of this report.

The Board notes the applicant's willingness to have a telephone installed in the Hihn residence and to initiate some training for A. Hihn who has previously worked with the plant operator. The Board supports all actions which will increase the degree of co-operation between energy developers and landowners.

The Board will direct in its approval, that pressure-sensitive, emergency shutdown valves be installed at each existing or any future well where the presence of $H_2S$ is detected. This will safeguard against an accidental release of gas from a well in the event of a third-person accident involving the wellhead.

# THE SIGNALTA APPLICATION 830087

## 7 IMPACT AND RELATIVE DESIRABILITY OF THE PROPOSAL AND ALTERNATIVES

### 7.1 Views of Signalta

Signalta stated that it had originally investigated the possibility of transporting the gas to the Heisler plant through the existing sweet gas pipeline. However, in discussions with the Board's Pipeline Department, it became evident that due to the presence of $H_2S$ in the gas and the possibility of stress corrosion cracking in the pipeline connections, the pipeline was not suitable for sour gas service.

The applicant explained that its proposed iron sponge unit would consist of a single tower partially filled with iron oxide impregnated wood shavings. The iron oxide, when kept moist, would react with $H_2S$

to form iron compounds, water, and sulphur. When the iron oxide is fully consumed, the tower would be opened and the sponge replaced. The applicant stated that it had received permission to dispose of the spent sponge material at the County of Flagstaff landfill site.

The process would not result in emissions of $H_2S$ or $SO_2$ under normal operating conditions. However, Signalta stated that the plant would be equipped with a flare stack for emergency situations and to flare the gas released during depressurization and change-out of the iron sponge tower.

The plant would also be equipped with a high pressure shut-down system to prevent over-pressuring of the iron sponge tower.

Signalta submitted that it did not expect the 10-31 well to produce any significant volumes of free water or hydrocarbons. However, the applicant had incorporated a knockout drum in the flare stack design. The knockout drum would prevent liquids from carrying over into the flare stack and resulting in smoke, or incomplete incineration of $H_2S$. Since the unit does not involve any moving equipment, Signalta stated that noise would not be a problem. The applicant concluded that the proposed facilities would have very little, if any, impact on area residents. Signalta tendered letters from each of the residents within 1.6 km of the 10-31 well site, stating that they had no objections to the proposed scheme.

Signalta stated that its decision to apply for iron sponge sweetening at the well site had been primarily for economic reasons and suggested that the only alternatives to its proposed scheme were to replace the pipeline and transport the gas directly to the Heisler plant, or to shut-in the well.

The applicant estimated that the cost of constructing a new pipeline would be approximately $250 000 and if the 10-31 well did not turn out to be a good producer, the pipeline could not be salvaged nor the expense offset. Also, replacement of the pipeline would result in additional surface disturbance. Signalta submitted that the iron sponge unit, on the other hand, would cost in the order of $80 000, was skid mounted, and could easily be adapted for re-use at another location.

With respect to shutting in the gas, Signalta stated that it would not be in the greater public interest to shut-in the well.

## 7.2 Views of the Interveners

None of the interveners lived in the immediate area of the 10-31 well and there was no suggestion that anyone would be adversely affected by the proposed iron sponge plant.

## 7.3 Views of the Board

The Board notes that the residents in the vicinity of the proposed facility were notified of the scheme and did not indicate any objections to the proposal.

As indicated by Signalta, the Board would not allow use of the existing pipeline to transport the gas from the 10-31 well to the Heisler gas plant. Even though the $H_2S$ content of the gas is extremely small, there would be a danger of pipeline failure and a resulting release of slightly sour gas to the atmosphere. (This matter is discussed further in section 9.6 of this report.)

The Board agrees that construction of a pipeline to connect the 10-31 well to the Heisler plant would result in additional surface disturbance and would be significantly more costly than the proposed iron sponge unit. The Board also recognizes that the proposed unit could be adapted for re-use, and transported to another location if the 10-31 well does not perform as expected.

The Board believes that the impact of the proposed unit would be small but could not be entirely eliminated, particularly because disposal of spent iron sponge would result in some impact. Proper disposal methods would be essential and would minimize this impact. Emissions from the flare stack would be infrequent but would occur during re-charging of the towers or during emergencies. However, the total amount of sulphur emitted as $SO_2$ over the life of the unit would be small. Consequently, the Board is prepared to approve the application. No special conditions, in addition to those which normally apply, are necessary.

## 8 DECISION

The Voyager Application 821089

The Board has requested additional information of the applicant and is deferring its decision with respect to the Voyager application until after the requested information has been received and evaluated. Its findings and decision will be issued as an addendum to this report.

The Signalta Application 830012

Having considered the evidence, the Board intends to approve Signalta's application subject to the receipt of the approval of the Minister of Environment with respect to environmental matters.

Signalta will be required to install pressure-sensitive, emergency shutdown valves at each existing, and any future wells, where the presence of $H_2S$ is detected.

The Signalta Application 830087

Having considered the evidence, the Board intends to approve the applied-for plant subject to receipt of the approval of the Minister of the Environment with respect to environmental matters.

DATED at Calgary, Alberta, on 30 June 1983.

G. J. DeSorcy

C. J. Goodman

C. J. Goodman

E. J. Morin

APPENDIX

# 9 OTHER MATTERS RAISED AT THE HEARING

## 9.1 Plant Proliferation and the Potential for Sulphur Recovery in East-Central Alberta

During the course of the hearing, the interveners expressed concern about the potential for further proliferation of gas plants in the area. Also, the feasibility of centralizing all the production in the area into one plant, that could recover sulphur, was discussed.

The Board has reviewed the estimated reserves and gas plant capacities for all the fields within a 127-township area (4572 square mile) generally centered around the Signalta-Heisler plant (see Figure 2).

The reserves in this area are such that when coupled with the typical gas marketing formula used by gas purchasers in the province, the likely maximum daily marketing volume is very close to the capacity of the existing gas plants in the area, including the Heisler plant. Therefore, the Board would not expect substantial additional gas processing facilities will be needed in the area in future, based on the known reserves. The Board has also studied the geology of the region and does not expect that significant additional gas reserves would be discovered.

The Board studied the $H_2S$ content of the gas fields in the general area and to its knowledge, the Lower Mannville (Basal Quartz) zone is currently the only horizon within a 40-km radius of the Signalta-Heisler plant that contains significant quantities of sulphur-bearing gases. The Board does not expect that the concentrations of $H_2S$ will increase beyond that described by the applicants.

In terms of sulphur recovery at a centralized gas plant, the Board has reviewed the design capacity of all sour gas plants within a 40-km radius of the Signalta-Heisler plant. The total maximum sulphur inlet rate of all of the plants would be less than the 10 t/d minimum considered necessary for sulphur recovery. This total is based on plant capacities but the actual sulphur inlet rates would be lower.

The Board estimates that if a sulphur recovery plant were built to process all the sour gas from the area studied, the sulphur plant alone would cost approximately $1.5 million. In addition to this, pipelines would be required to move the sour gas from the points of production to this central sulphur recovery plant. Looking at the overall region studied and the sour plants identified, and considering that these plants are scattered over a distance of 120 km, the Board estimates that the gathering system would require over 200 km of new pipeline costing tens of millions of dollars and having a significant land-use impact.

Additionally, certain of the existing gathering systems would have to be replaced because of varying flow rates and pressures and compression facilities and line heaters would be required along other gathering systems.

Having these massive expenditures and land-use impacts in mind, and recognizing that the total emissions over the area are less than 10 t/d and are in a manner such that the ambient air quality standards are met, the Board concludes that the gathering of all this sour gas to a single central sulphur recovery facility is not only uneconomic, but not practical nor in the public interest.

9.2 Complaints Respecting the Zoller & Danneburg - Killam Gas Plant

The Board takes seriously complaints brought to its attention respecting any gas plant in Alberta that does not conform to minimum standards or that negatively impacts on nearby residents. The Board appreciates the comments of V. Coates, who appeared as a witness at this hearing to relate his experiences with the Zoller & Danneburg gas plant. Following the hearing, the Board asked its staff to inspect the subject plant. Staff inspections had been made previously by the Wainwright Area Office and some work was being done. Further work has been required of the plant operator and special monitoring will take place to ensure that standards are being met.

9.3 $SO_2$ Emissions from the Proposed Signalta Plant as Compared to Those Elsewhere in the Province

The Board notes that at the hearing, references were made to other areas in the province where sulphur is recovered, and to the Lodgepole blowout. The Board considers it important that the emissions expected from the proposed facility be viewed in the proper perspective.

The Signalta plant would emit a maximum of 5.0 t/d of $SO_2$ (2.5 t/d of sulphur), and while this rate is not insignificant, the emission is very small in comparison to larger plants which recover a high percentage of the sulphur in the feed gas, but also emit $SO_2$. Some of these plants emit up to 20-30 times as much $SO_2$ as would the proposed plant, through stacks designed to ensure that ground level standards are satisfied.

The proposed Heisler plant on the other hand, is typical of some 42 plants throughout the province that have approval to process gas and emit varying amounts of sulphur up to a maximum of 10 t/d. For the most part, these plants operate without difficulty or significant impact on nearby residents.

The Lodgepole blowout involved a well with much higher flow potential than those in the Heisler area, and with a much higher percentage of $H_2S$ in the gas. Sulphur emissions from the Lodgepole well were probably 1000 times greater than the emissions which could occur from a typical well in the subject area.

## 9.4 Flare Stack Height

The Board believes that the matter of stack height needs to be addressed because R. Kroetsch expressed concern that the proposed 38-metre flare stack at the Signalta plant would be inadequate. He made reference to the Shell-Rosevear plant (near the Town of Edson) which he stated has a stack 375 feet (114 m) in height.

Records for the Rosevear plant show that the Rosevear flare stack is 45.7 m in height compared to 38 m for the Heisler flare stack. Mr. Kroetech may have been referring to the Rosevear incinerator stack, which is 91.4 m high and, even though almost 96 per cent of the inlet sulphur is recovered, would emit several times the quantity of sulphur that would be released by the Heisler stack.

Whether it is designated an incinerator or flare stack, each such facility is designed with consideration given to many variables including; the volume of gas to be burned, $H_2S$ content, adjacent terrain, tree cover, and whether incineration takes place at the top or the base of the stack.

The Board believes that the important feature is not the actual height but rather that the height of stack used at each plant is sufficient to ensure that ground level standards for maximum $SO_2$ concentrations are not exceeded. All stacks in Alberta are designed to provide for the safe and environmentally acceptable incineration of the gases that they are expected to release to the atmosphere.

## 9.5 The Need for Communications With the Public

Guide G-26, which sets out the Board's requirements for gas processing applications, indicates that a lack of communication with local residents about a sour gas plant to be constructed or modified may lead to complications and delays in the disposition of an application.

In several recent applications for both sour and sweet gas plants, the Board has noted that local residents were not well informed by the applicants about the details of the project (size, type of gas to be handled, plans for environment protection, noise, safety, and emergency procedures). The Board emphasizes that appropriate communication must take place with residents in the area before filing an application, and the results of such contact should be reported as part of the application.

The Board intends to issue an informational letter to the gas industry, drawing this matter to its attention.

9.6 Suitability of Mechanical Interference Fit Joints for Sour Gas Pipeline Service

From many years of experience, the Board has determined that $H_2S$ can be transported safely through properly designed and operated pipelines. However, even very minute quantities of $H_2S$ can cause corrosion and pipe degradation through complex failure mechanisms. For this reason, the Board carefully considers the suitability of each application it receives to construct a pipeline involving sour gas.

The Pipeline Regulations refer to several documents and require the designer to conform to their requirements when designing pipelines. For sour gas, the designer must first refer to Canadian Standards Association (CSA) Z184-MI983 Gas Pipeline Systems. In addition, the regulations and standard also refer to National Association of Corrosion Engineers (NACE) standard MR-01-75-1980, Sulphide Stress Corrosion Cracking Resistant Metallic Material For Oil Field Equipment. These standards are consensus standards and are generally accepted as good minimum practice by the Board.

In this particular situation, tie-in pipelines to the Signalta processing plant are existing pipelines constructed using mechanical interference fit (MIF)joints . MIF connections involve cold-forming end preparations that could make the cold-formed section very susceptible to stress corrosion cracking in the presence of $H_2S$. Under the requirements of CSA Z184-MI983 this type of joint is not allowable in sour service. By definition, sour gas is any gas having even a very small partial pressure (0.35 kPa) of $H_2S$. Even though in this case the percentage of $H_2S$ is very low (15-800 ppm), the Board agrees with and has elected to adhere to the requirements of CSA Z184-MI983 to ensure the continuing integrity of the pipelines.

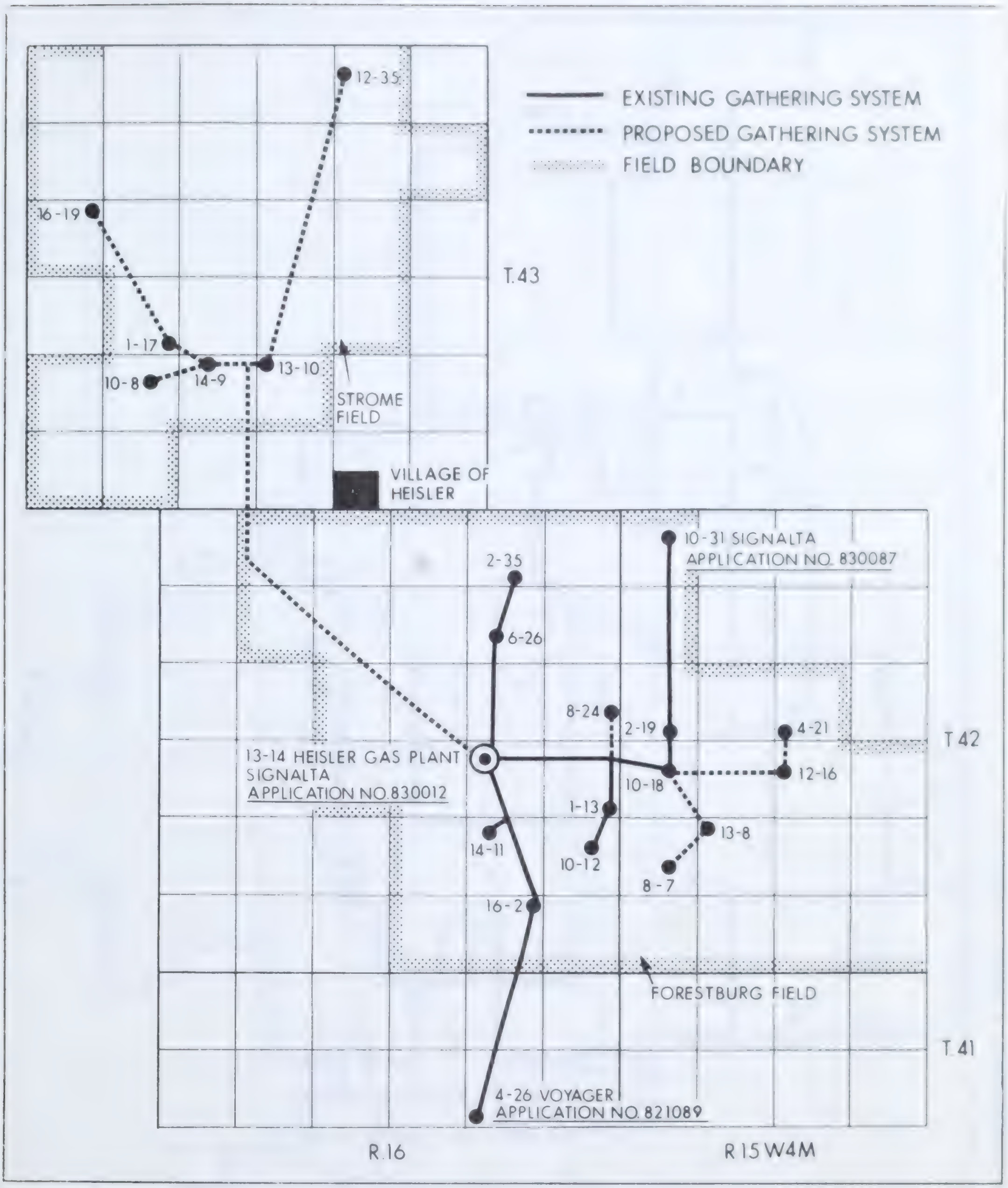



FIGURE 1 PROPOSED AND EXISTING GAS PLANTS AND GATHERING SYSTEM

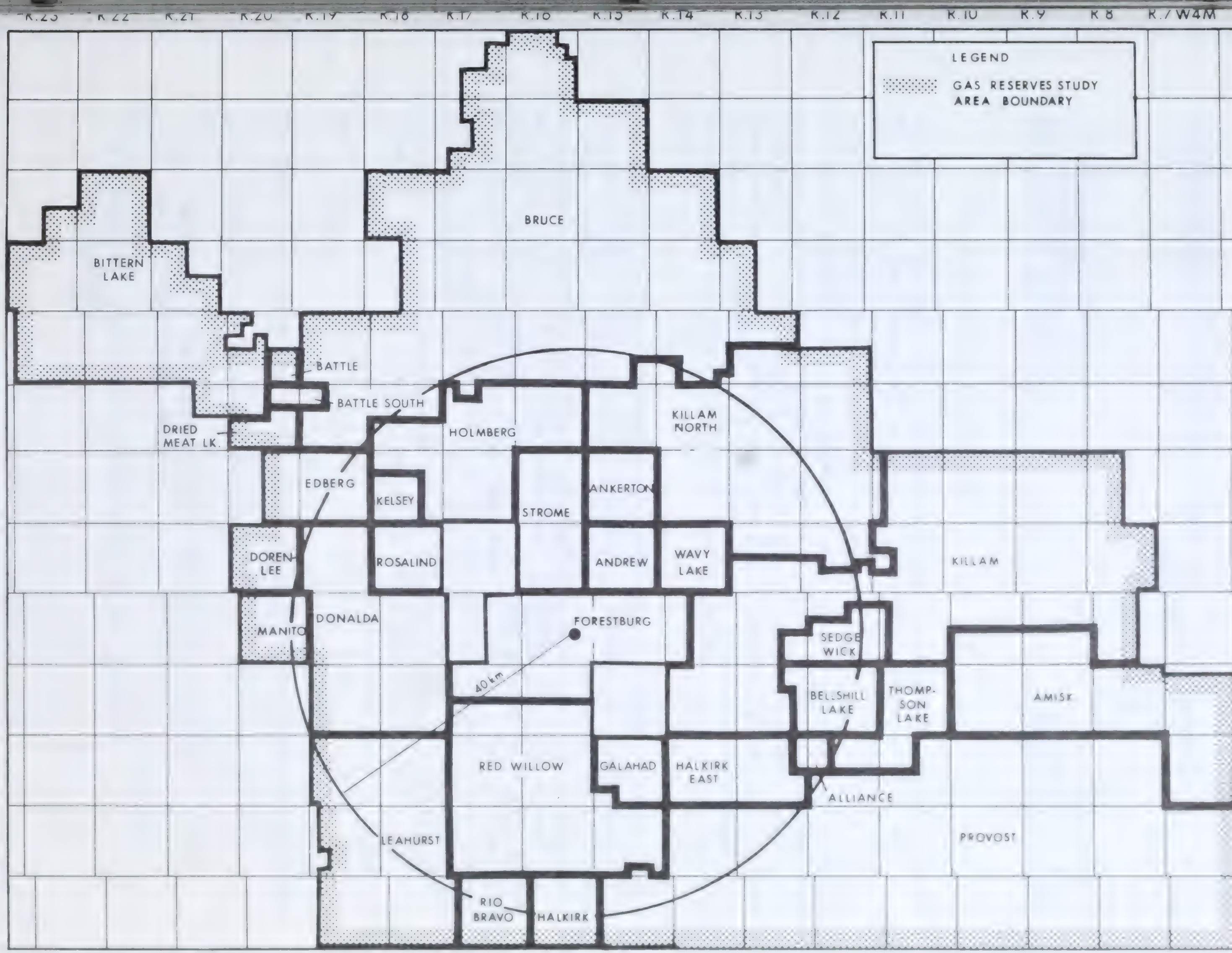



FIGURE 2 GAS RESERVES STUDY AREA

ERCB

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta



VOYAGER PETROLEUMS LTD.
GAS PROCESSING PLANT
EAST CENTRAL ALBERTA

Addendum to
Decision D 83-10
Application 821089

## 1 THE APPLICATION AND HEARING

Voyager Petroleums Ltd. (Voyager) applied, pursuant to section 26 of the Oil and Gas Conservation Act, for approval to construct and operate sour gas processing facilities at its well located in Lsd 4-26-41-16 W4M (4-26 well). The facilities would be designed to process a maximum of 56.4 thousand cubic metres per day ($10^3$ $m^3/d$) of sour gas containing 33.8 cubic metres ($m^3$) of hydrogen sulphide ($H_2S$) from which 54.0 x $10^3$ $m^3/d$ of sweet gas would be recovered and transported to the Signalta-Heisler gas processing plant for further processing. A maximum of 0.092 tonnes per day (t/d) of sulphur dioxide ($SO_2$) would be emitted to the atmosphere from a 12.2 metre (m) flare stack.

The application was considered at a hearing in Heisler, Alberta, on 29 and 30 March 1983, with G. J. DeSorcy, P.Eng., C. J. Goodman, P.Eng., and E. J. Morin, P.Eng., sitting. In its report D 83-10 for Application 821089, the Board deferred its decision pending receipt and evaluation of further information regarding the iron sponge process as an alternative to amine sweetening at the 4-26 well site. The additional information was requested by letter dated 14 June 1983 and was received by the Board on 30 June 1983. Copies of the letter and reply from Voyager were provided to all parties registered at the hearing. For the convenience of the reader, relevant sections of report D 83-10 have been incorporated into this report.

## 2 ISSUES

The Board considers the issues with respect to the application to be:

- need for the proposed facilities,
- impacts and relative desirability of the proposal and alternatives, and
- special conditions of operation if the proposal is approved.

## THOSE WHO APPEARED AT THE HEARING

| Principals and Representatives (Abbreviations used in Report) | Witnesses |
|---|---|
| Voyager Petroleums Ltd.<br>(Voyager)<br>J. Schlegel | J. Goemans, P.Eng.<br>of Voyager Petroleums Ltd.<br>D. Padula, P.Eng.<br>of Swinarton Engineering Ltd. |
| Signalta Resources Limited<br>(Signalta)<br>J. B. McCashin | J. Stueck, P.Eng.<br>E. Dhenin,<br>both of Signalta Resources Limited<br>D. Widynowski, P.Eng.<br>of Widy Engineering Ltd. |
| East Central Landholders Protective Assoc.<br>(Protective Assoc.)<br>E. Waite | E. Waite |
| Hastings Coulee Community<br>(Community)<br>W. Henderson | W. Henderson |
| Warren Henderson Family<br>(W. Henderson) | W. Henderson |
| Robert Coulthard Family<br>(R. Coulthard) | B. Coulthard<br>V. Coates |
| Einar and Rhoda Fossen | |
| Art Hihn Family<br>(A. Hihn)<br>F. Hihn | M. Hihn<br>A. Hihn |
| Colin and Barbara Kroetsch<br>R. Kroetsch | C. Kroetsch<br>R. Kroetsch |
| The Town of Daysland<br>R. Damberger | |
| The Village of Forestburg<br>C. Farvolden | |

THOSE WHO APPEARED AT THE HEARING (cont'd)

| Principals and Representatives (Abbreviations used in Report) | Witnesses |
|---|---|
| Forestburg Veterinary Clinic | |
| Aberan Angus Farm (R. Tate) | R. Tate |
| The Crown<br>S. L. Dobko<br>of Alberta Environment | |
| Energy Resources Conservation Board staff<br>M. J. Bruni<br>E. P. Moeller, C.E.T.<br>L. S. Fillion, C.E.T. | |

## 3 NEED FOR THE PROPOSED FACILITIES

### 3.1 Applicant's Views

The applicant stated that the 4-26 well had been completed and flow tested in May 1982. Limited field testing of the well at that time indicated that there was no $H_2S$ present in the gas stream. Subsequently, construction of a sweet gas pipeline to tie the well into the Signalta-Heisler plant was completed in June 1982. The well was brought on stream in early July and produced for approximately 17 hours. Voyager stated that the well was shut-in at 10:00 a.m. on 7 July 1982, as it was suspected of being responsible for the gas produced from the Signalta-Heisler plant containing concentrations of $H_2S$ in excess of the limit of 16 parts per million (ppm) for sales gas. The concentration of $H_2S$ at the 4-26 well was then measured, and determined to be 370 ppm. Further testing of the well in August 1982 measured an average $H_2S$ concentration of 580 ppm.

Voyager said that it had been aware that Signalta was planning to apply for the installation of gas sweetening facilities at the existing Heisler gas plant location in Lsd 13-14-42-16 W4M. The applicant stated that initially it applied to the Board for the installation of a temporary amine sweetening unit at the 4-26 well because it was under the impression that once sweetening facilities had been installed at the Heisler plant, Voyager would be able to discontinue the use of its wellhead sweetening unit, and produce the 4-26 well directly to the Heisler plant.

In subsequent discussions with the Board's Pipeline Department, Voyager was informed that the pipeline which tied the 4-26 well into the Heisler gas plant was not suitable for transporting gas containing even such relatively small amounts of $H_2S$. Therefore, Voyager concluded that if it were to produce the 4-26 well, sweetening would have to take place at the wellhead and it had then requested that the Board consider its application as one for a permanent installation.

### 3.2 Interveners' Views

Although the majority of the interveners did not question the need for the facility, R. Kroetsch stated that, since there is presently a surplus of gas in the province, it was not really necessary to produce the gas.

### 3.3 Board's Views

The Board notes that Voyager has leased mineral rights, drilled and completed wells capable of producing natural gas, and has obtained the necessary approvals to produce the gas. In designing for the production of certain wells in the area, the applicant did not adequately anticipate the presence of $H_2S$ and consequently production of its 4-26 well had to be halted when the presence of $H_2S$ was detected.

The Board believes that Voyager has the right to produce its gas reserves subject to the pertinent regulations, standards, and guidelines. Since production of the reserves through presently existing facilities would violate various regulations, the Board sees a need to modify or add to those facilities in order to allow Voyager to resume production of its gas and recovery of an Alberta resource to continue. The Board therefore concludes that, provided the impact of such facilities would not be unacceptable, there is a need for gas sweetening facilities in the area, either on site or at a central location.

Section 9.1 of report D 83-10 discusses the feasibility of transporting the sour gas to a possible central sulphur recovery plant designed to handle all the sour gas in the area. The analysis led the Board to conclude that such a scheme would not be practical.

## 4 IMPACT AND RELATIVE DESIRABILITY OF THE PROPOSAL AND ALTERNATIVES

### 4.1 Applicant's Views

The applicant testified that the proposed amine gas sweetening plant would be skid mounted, housed in a metal building, and totally enclosed by a chain link fence. Voyager stated that the facility would be equipped with a 12.2-m flare stack designed to maintain the ground level concentration of $SO_2$ below the Clean Air Act guideline of 0.17 ppm for 1 hour. Voyager claimed that, on average over a year, the $SO_2$ would be emitted at a rate that was only 50 to 60 per cent of the rate applied for, due to market conditions for the gas produced.

Voyager stated that its proposed unit had been greatly modified and simplified from a typical amine sweetening unit but that it would still be reliable, although somewhat less flexible, when compared with conventional systems. Voyager was confident that its proposed unit would be capable of sweetening the gas efficiently and safely in conformance with all government regulations and requirements.

The safety features of the plant would include automatic shutdown valves on the plant inlet and outlet gas lines, and safety relief valves connected to flow into the flare stack and to prevent overpressuring of the process vessels. The flare stack would be equipped with a gas pilot and an automatic ignition system to ensure the complete combustion of any vented gases. Voyager stated that the plant would be attended during the day.

Voyager said that its proposed plant had been designed to comply with all of the standards and requirements of the Board and Alberta Environment. The standards and requirements had been established in order to protect the public, ensure environmental quality, and provide for the safe and efficient operation of all gas processing facilities.

Voyager stated that its plant would be one of the smallest in Alberta and that it did not expect any adverse health effects or complaints as a result of its operations. However, it stated that it would be willing to investigate any complaints. Additionally, Voyager offered to install corrosion monitoring stations, and to install a mobile $SO_2$ monitoring trailer for a 1-month period, the first time a complaint was received.

With respect to the possibility of expanding the plant in the future, Voyager stated that its gas contract restricted it to producing a maximum of $56.4 \times 10^3$ $m^3/d$ of gas from its reserves in section 26-41-16 W4M, which would be produced by the 4-26 well. Furthermore, it could not foresee the gas contract rate being increased. The applicant did indicate that an offset well might be drilled sometime in the future in an effort to maintain the throughput of the plant as the output of the existing well declined. Voyager emphasized that, even if a second well were tied in, the throughput and emission rates established for the plant would remain the same as applied for and no additional impact would result.

Voyager stated that the alternatives to the installation of an amine unit at the 4-26 well site were installation of an iron sponge unit or construction of a new pipeline between the well and the Heisler gas plant. Although the iron sponge process would not result in $SO_2$ emissions to the air, it would produce a solid waste by-product and the spent sponge material would have to be disposed of about every four months. The spent sponge and its associated acidic waters would have to be neutralized and then trucked to the County of Flagstaff landfill site.

Voyager also stated that the iron sponge process would not remove unwanted carbon dioxide ($CO_2$) from the gas and was not recommended for use when the concentration of $H_2S$ and the volume of gas to be sweetened were as large as in this case. Further, the capital cost of a suitable iron sponge unit would be approximately $400 000.

The applicant testified that the pipeline which ties the 4-26 well into the Heisler plant could not be upgraded to allow transportation of sour gas. Replacement of the pipeline would cost in the order of $275 000, and processing the sour gas at the Heisler plant could involve an additional $200 000 in order to buy a share of the Signalta plant. This compared with the $208 000 capital cost for the proposed unit. Furthermore, burying a new pipeline would result in additional surface disturbance over its entire 8-km length and would necessitate the transportation of sour gas over a longer distance.

Voyager emphasized that there was no production history for the pool and it is difficult to predict how the well will perform. A new pipeline would have no salvage value and would therefore represent an added economic risk if the 4-26 well did not turn out to be a good producer. Alternatively, if the proposed well-site sweetening unit were installed but the well did not perform as expected, it would be salvaged and used for some other application.

Neither of the alternatives would result in the creation of an additional emission source. Voyager agreed that, in general, it would be better to have a single large $SO_2$ emission source as opposed to a number of small sources with the same cumulative emission volume, but indicated that in this instance the additional emission source was justified. The applicant pointed out that had the pipeline connecting the 4-26 well to the Heisler plant been suitable for transporting sour gas, Voyager would not have applied for a well-site sweetening unit.

4.2 Interveners' Views

The interveners generally expressed concern that emissions from the plant would have an adverse effect on certain individuals in the area who have known health problems. They suggested that anything which would impact on the health of people should not be allowed.

R. Coulthard stated that the applicant should be required to prove that its proposed facilities would not cause odours, health problems, or property damage. He further stated that certain types of health damage are irreversible and an investigation of any damage after the fact would be of no benefit to the affected individuals. He stated that he was not in favour of installing gas sweetening facilities at the 4-26 site unless there were no atmospheric emissions.

R. Kroetsch stated that Voyager should be required to transport its gas to the Heisler plant for processing.

The Protective Assoc. was concerned that, if additional wells were tied into the plant at some future date, operating problems would increase and the community would be subjected to an increasing risk. It also expressed concern that emissions from the plant would cause acidic precipitation which would result in property damage.

The interveners generally indicated that they were not as concerned with gas processing facilities which performed as intended as they were with the effects when operating problems developed. They suggested that once a facility was in place, and should problems arise, they would have great difficulty in getting corrective action initiated. V. Coates, on behalf of R. Coulthard, related the problems he had encountered over a three-year period when a gas sweetening plant near his home did not operate properly (discussed in section 9.2 of Decision D 83-10). The interveners feared that they would experience similar problems.

### 4.3 Board's Views

The Board attempted to compare the available alternatives to the Voyager proposal but concluded in Decision D 83-10 that it did not have sufficient information to adequately evaluate the alternative of sweetening by an iron sponge process, cost estimates given by the applicant, and how $CO_2$ in the gas affected the entire operation. The Board was also not satisfied that Voyager had fully evaluated and properly compared the environmental impacts that would result from the use of an iron sponge unit as compared to those that would occur if the proposal was approved. The Board therefore requested additional information of the applicant in a letter dated 14 June 1983 and received that information in a letter dated 30 June 1983, copies of which were sent to all participants in the hearing.

### 4.4 Voyager's Response to Board Questions

In support of its application, Voyager stated that its proposed amine sweetening unit would emit a maximum of 0.092 t/d of $SO_2$, resulting in a maximum ground level concentration of 0.044 ppm at a distance of 158-m. The applicant noted that 0.044 ppm is approximately 1/4 of the provincial standard. In addition, the predicted ground level concentration of $SO_2$ would approach zero at a distance of 760-m.

Voyager stated that while the iron sponge process would not result in emissions of $SO_2$ during normal operations, some flaring would occur during depressuring of the vessels prior to replacing the spent sponge material. In its view, the vessels would require changeout every four months and would require the disposal of 157 $m^3$ (5600 bushels) of spent material at a landfill site.

Voyager stated that an iron sponge is not recommended for reducing the $H_2S$ content of natural gas with concentrations as high as in this case. The applicant contended that, since the iron sponge process does not remove $CO_2$, it would not be able to meet its sales gas contracts unless the $CO_2$ could be removed or diluted at the Signalta plant. Voyager noted that the iron sponge process would result in a less flexible process that would be significantly more expensive to install. Also, it would result in higher operating costs and increased processing fees at the central plant.

None of the interveners commented on the additional information submitted by Voyager.

## 4.5 Board's Views

The Board has considered the alternatives to amine sweetening at the 4-26 well, and believes that the iron sponge process should not be utilized in this case because there is significant doubt that the process can be utilized for the removal of $H_2S$ in quantities above 300 ppm. The Board also notes that the volume of spent iron sponge material would be sizeable and that it would have to be disposed of at an approved landfill site. Therefore, the iron sponge process would have an environmental impact that would be different but not necessarily any less than that of an amine unit.

The Board has also investigated the alternative of replacing the pipeline between the 4-26 well and the Signalta plant, and finds that a new pipeline would have a major impact from the viewpoint of additional land disturbance. The Board concludes that replacing the pipeline is not a superior alternative to either the amine unit or the iron sponge process, and that emissions would only be transferred to another location.

The applied-for amine unit would result in the emission of only a small amount of $SO_2$, a maximum of 0.092 t/d. Emissions would occur in a manner such that existing ground level concentration standards would be more than satisfied.

The standards have been set by Alberta Environment following considerable research and study and are designed to safeguard against deleterious impacts on the health of humans and plant life. The Board is thus satisfied that the minimal emissions from the proposed facility would not be such as to merit denial of the application.

Having considered the evidence presented, the Board believes that the amine unit will have the least impact on the area, will operate within the applicable regulations and standards, and is the most practical alternative under the circumstances.

# 5 SPECIAL CONDITIONS OF OPERATION

## 5.1 Applicant's Views

In response to the concerns expressed by the Community, Voyager stated that it was willing to install permanent corrosion monitoring stations on the prevailing downwind side of the plant. Additionally, if a written complaint was received from a downwind resident within the first year of plant operation, it would set up an $SO_2$ monitoring trailer within 1 km of the plant site.

The applicant stated that it did not wish to be restricted to processing gas from only the 4-26 well, as recommended by the Community. It wished to maintain flexibility to tie-in an offset well to maintain the throughput of the plant, given its estimate that production from the 4-26 well would decline at a rate of about 10 per cent per year. Voyager did state, however, that it would be willing to commit itself to process not more than $56.4 \times 10^3$ $m^3/d$ of gas and to emit not more than 0.092 t/d of $SO_2$ over the life of the project.

Voyager was opposed to the formation of a committee of local people with the power to shut down the plant if the committee deemed it necessary. The applicant stated that the Board and Alberta Environment have mandates to require a plant shut-down if necessary, and it did not believe that a local committee of concerned but non-specialized people would be able to deal appropriately with any problems that might occur. Voyager undertook that any complaints would be dealt with in a professional manner.

The applicant stated that, although it was concerned with the general health and welfare of the community, it had designed its plant to meet government standards and all the pertinent regulations, and believed that adequate consideration had already been given to health matters.

## 5.2 Interveners' Views

The Community and W. Henderson stated that they would have no objection to the proposed plant if Voyager would consent to the following conditions:

1. Permanent corrosion monitoring stations to be installed on the prevailing downwind side.

2. The plant to be shut down as quickly as possible if a complaint is signed by two persons of an advisory committee set up by the Community. This committee shall consist of at least three persons selected by the people in the community and a designate of Voyager.

3. If it is determined that the cause of the first complaint is due to a malfunction of the plant which cannot be immediately corrected, and the committee is satisfied this is the case, Voyager will install a rental $SO_2$ monitoring trailer for up to one month in a location within 1 km from the sweetening facility. The monitored data will include $SO_2$ concentration in the air, wind direction, and wind velocity. The monitoring trailer will be operated by an independent company such as

Western Research of Calgary. This company will furnish a written report to Voyager, the Committee, and the ERCB. At a meeting of the Committee, the report will be explained and discussed fully and further action will be decided upon.

4. The sweetening plant can only be used for one well.

5. Special considerations must be given to health, because of existing problems with health - asthma, leukemia, etc.

The other interveners supported these proposals. W. Henderson also requested that, because of existing health problems, an air quality monitor be set up in his yard and that his family be trained to read it. He said that the establishment of an advisory committee would allow for community involvement in the project, would help to educate the people, and would ensure the plant would not operate in an unsafe or improper manner. Further, W. Henderson stated that Voyager had committed itself to the processing of gas from only the 4-26 well at a public forum held prior to the hearing, and Voyager should be required to live up to its commitment.

The Protective Assoc. agreed that Voyager should be restricted to processing gas from only the 4-26 well and expressed concern that the applicant would try to add more and more wells to the plant, pushing the unit to its limit until problems became inevitable.

5.3 Board's Views

Having regard for the residents' concerns, the Board sees a need for the operator of the well and the plant to have easy 24-hour access to the facility, and provide his mobile phone number to nearby residents. The Board believes that Voyager must develop effective communications with residents and keep them well informed of its intentions in the area. The Board sees a need for the applicant to take special care to ensure that, except in emergencies, flaring of gas does not take place without a demonstrated need, or without informing nearby residents.

Regarding safety, the Board notes that the production system would operate at pressures in the order of 250 pounds per square inch (psi) compared to the equipment design pressure of 720 psi, which is also well above the shut-in pressure of the well. Voyager will install an $H_2S$ analyzer that will monitor the $H_2S$ content of the sweetened gas and shut down the plant if the limit is exceeded. Additionally, the plant will be equipped with automatic shutdown valves on the plant inlet and outlet gas lines, and the vessels will be protected against overpressure by safety valves.

Although the Board agrees with Voyager that the proposed plant is one of the smallest sweetening units in the province, it believes that Voyager's proposal to install a mobile $SO_2$ monitoring trailer for a month the first time a complaint is received, is inadequate. In addition to Voyager's offer to install corrosion stations and exposure cylinders, the Board concludes that Voyager should install an $H_2S/SO_2$ monitoring trailer for a 2-month period following start-up of the facility. The results of the survey would be made available to the public, Alberta Environment, and the Board. Additionally, the Board will instruct its staff to frequently visit the proposed plant for operational inspections and to periodically monitor the area with the Board's own mobile monitoring equipment.

With respect to W. Henderson's concern that the plant might be enlarged, the Board notes Voyager's commitment to restrict processing capacity of the plant to the applied-for $56.4 \times 10^3$ $m^3/d$. In addition, any expansion of the plant or another pipeline to tie-in additional wells would require new applications which would be subject to review by government, the Board, and the public.

## 6 CONCLUSION AND DECISION

Having considered the evidence, the Board is prepared to approve Voyager's application subject to the receipt of the approval of the Minister of the Environment with respect to environmental matters. While the Board believes that the impact of the plant and emissions over the life of the project would be small, it has requested Alberta Environment to condition its licences to require, in addition to the usual exposure cylinders and emission data, the installation of a mobile monitoring trailer for 2 months following start-up of the proposed plant. Results of the monitoring shall be made available to the public, the Board, and the government.

DATED at Calgary, Alberta, on 22 August 1983.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy

G. J. DeSorcy

C. J. Goodman

C. J. Goodman

E. J. Morin

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta



HUDSON'S BAY OIL AND GAS COMPANY LIMITED
SOUR GAS PIPELINES
REINJECTION PIPELINE
FUEL GAS PIPELINE
BRAZEAU RIVER - WEST PEMBINA AREA

Decision D 83-11
Applications 810924, 810925, 810926, and 820251

# 1 THE APPLICATIONS AND HEARING

## 1.1 The Applications

Hudson's Bay Oil and Gas Company Limited (HBOG) applied pursuant to Part 4 of the Pipeline Act for permits to construct pipelines to gather sour gas from wells in the Brazeau River - West Pembina area for processing at its approved Brazeau River gas processing plant, to return residue gas for area gas cycling schemes, and to distribute fuel gas to field facilities.

The figure shows the location of wells and proposed pipelines and gas plants in the Brazeau River - West Pembina area. Details of the applications are set out below:

### North Lateral

Application 810924 was to construct approximately 24.81 kilometres (km) of 168.3-millimetre (mm) outside diameter (OD) pipeline, 4.24 km of 219.1-mm OD pipeline, and 7.98 km of 273.1-mm OD pipeline to transport sour natural gas with a maximum hydrogen sulphide ($H_2S$) content of 252 mol/kmol from wells located in Legal Subdivision 6 of Section 29, Township 47, Range 11, West of the 5th Meridian, Lsd 7-34-47-12 W5M, Lsd 3-32-47-13 W5M, Lsd 8-7-48-13 W5M, and Lsd 6-6-48-13 W5M, to the gas plant in Lsd 6-10-47-14 W5M.

### West Lateral

Application 810925 was to construct approximately 13.32 km of 168.3-mm OD pipeline and 9.05 km of 219.1-mm OD pipeline to transport sour natural gas with a maximum $H_2S$ content of 196.1 mol/kmol from wells located in Lsd 6-1-47-16 W5M, Lsd 2-11-47-15 W5M, Lsd 6-31-46-14 W5M, and Lsd 15-9-47-14 W5M to the 6-10 gas plant.

Reinjection

Application 810926 was to construct approximately 19.82 km of 88.9-mm OD pipeline and 1.63 km of 114.3-mm OD pipeline to transport sweet natural gas from the 6-10 gas plant for reinjection into wells located in Lsd 14-2-27-15 W5M and Lsd 9-1-48-14 W5M.

Fuel Gas

Application 820251 was to construct approximately 57.5 km of 88.9-mm OD pipeline to transport fuel gas from the 6-10 gas plant to the well sites, line heaters, and other facilities.

## 1.2 The Hearing

V. E. Bohme, P.Eng., C. J. Goodman, P.Eng., and J. A. Bray, P.Eng., heard the applications at a public hearing on 21-22 June 1983, in Calgary, Alberta. The participants at the hearing are shown in the appendix.

An initial motion by Amoco to adjourn the hearing was supported by most of the interveners. The basis for the motion was that the applicant had not concluded technical and financial agreements with area gas producers and that the hearing for the nearby Petro-Canada proposed gas plant would be in a few weeks. The interveners argued that the applications were premature and that the Board should defer its decision pending completion of agreements and clarification of the role of the Petro-Canada plant in the handling of gas from the area. The Board ruled that it wished to hear the applications in order to obtain more evidence to permit a complete evaluation of the questions of whether the applications were premature or whether its decision should be deferred. Further, the Board believed that after consideration of the applications, it could appropriately condition any approvals which it might issue, which would address those concerns of interveners that were within the Board's jurisdiction.

Regarding the interveners concerns about lack of agreements with the applicant, the Board believes that these concerns can best be resolved through the processes of pooling and voluntary unitization. In the event that the negotiations are not productive, the parties have recourse to other avenues such as the common carrier, purchaser and processor, or pooling provisions of the Oil and Gas Conservation Act.

# 2 ISSUES

Each of the interveners at the hearing cited several specific areas of concern particular to its holdings and interests in the Brazeau River - West Pembina area. These concerns included the magnitude of plant processing and pipeline transportation fees, safety, depletion methods, gas cycling schemes, and the absence of pooling or unit agreements. In response to an objection by HBOG, the Board indicated that the matters of gas plant financing and processing fees were not within its jurisdiction and would not be considered at the hearing.

For the purposes of its review of the applications, the Board believes the issues to be:

- o need for the pipelines
- o economic, orderly, and efficient development of the area
- o safety

## 3 NEED FOR THE PIPELINES

HBOG stated that construction of its approved gas plant located in 6-10-47-14 W5M was progressing and that permits for the proposed pipelines were needed so that gas would be available to the plant by the estimated on-stream date in May 1984. HBOG stated that it had requested gas nominations to its plant in October 1981 prior to the hearing for that facility, that it had significant interest in the reserves of the wells proposed for tie-in and, that its proposed gathering system was not significantly different than shown at the time of its plant application and hearing. Furthermore, it had the right to produce from the 6-1, 2-11, 7-34, 3-32 wells, and to cycle gas in the Brazeau River Nisku J Pool using the 6-6 and 9-1 wells. It indicated that while no drilling spacing unit (DSU) pooling, processing, or transportation agreements had been reached with area operators for the remaining wells to be tied in, it believed the necessary financial and technical agreements could be in place and the pipelines constructed prior to the proposed plant start up.

Because of concerns expressed by interveners who are owners in certain wells and the need for pool cycling, which could affect the availability of gas and thus the need for the pipelines, the Board has reviewed the concerns expressed at the hearing and intends to deal briefly with each well or pool.

### 3.1 Wells

<u>6-31 and 15-9</u>

Texaco indicated to the Board that it had not reached an agreement with HBOG to complete DSU pooling for either of the 6-31 or 15-9 wells and had not nominated any of its gas from these wells to be gathered by the proposed HBOG pipeline system or processed at the HBOG plant. It was Texaco's position that until agreements are in place it was premature for HBOG to apply for facilities to handle and process production from those wells on behalf of Texaco.

Although Home Oil has an interest in the 15-9 well, it did not oppose the applications.

6-29 and 7-34

Amoco submitted that these two wells were not originally included in the applicant's gas plant application and further submitted that it, Petro-Canada, and Texaco were preparing a scheme to tie-in and produce several wells north of the 6-29 and 7-34 wells and their scheme could also include those wells. Amoco contended that the connection of these two wells to the Petro-Canada proposed gas plant at 4-31-48-12 W5M would provide for better liquid recovery in the Carbonate Bank area and would minimize pipelines in an environmentally sensitive area.

Amoco also indicated that it had yet to agree on the DSU pooling for the 6-29 well, the processing of its 6-29 gas at the HBOG plant, or on participation in the HBOG plant.

Shell has an interest in the 6-29 well DSU and opposed the pipeline approval on the basis that it has not made any arrangements with HBOG regarding DSU pooling, processing, or transportation of gas from that well. It also contended that transporting and processing the gas to the HBOG plant may not be the most economic, orderly, or efficient disposition. Both Shell and Amoco stated that they believed it was inappropriate to approve the construction of the pipelines until there was at least agreement on pool unitization.

The Board believes that the need for a pipeline has not been established where the proposed supply well does not have the right to produce. Thus the DSU pooling agreements for the 6-31, 15-9, and 6-29 wells must be complete before the portions of the proposed pipeline to those wells are approved for construction.

Accordingly, the Board is prepared to issue unconditional permits for those portions of the proposed pipelines connecting wells where DSU pooling is complete and to issue conditioned permits for those portions of the proposed pipelines connecting wells where DSU pooling is not complete.

The Board agrees with the applicant that the HBOG plant is a suitable location for processing gas from the 6-29 and 7-34 wells. Concerning the 7-34 well, the Board agrees that the reservoir must not be produced beyond the dewpoint pressure of the reservoir fluid. However, the Board is prepared to permit the pipeline and allow production from the well subject to the applicant's undertaking to establish the dewpoint pressure of the reservoir fluid from the 7-34 well and not to produce below that pressure, prior to establishing the optimum depletion scheme for conservation of hydrocarbons.

3.2 Cycling Schemes

A number of currently proposed cycling schemes, or ones which may become necessary to effect hydrocarbon conservation, were also mentioned by the interveners. The Brazeau River Nisku K and F Pool schemes are discussed below.

K Pool

HBOG currently has a cycling scheme proposal before the Board for this pool. It stated that the K Pool is an isolated pinnacle reef reservoir containing retrograde gas condensate with a virgin pressure of 70 600 kPa and a dewpoint pressure of 30 200 kPa. The raw gas reserve in place is 650 $10^6$ $m^3$ and HBOG proposed to produce at a rate of 350 $10^3$ $m^3/d$ for about 15 months when the reservoir pressure would then be about 34 000 kPa. HBOG planned to implement a gas cycling scheme with Petro-Canada at that time. It noted that primary production from Petro-Canada's 14-2 well could also be processed at its plant.

While Petro-Canada agreed the HBOG plant was a logical location for processing K-Pool production, it expressed concern that it would be drained by the HBOG 2-11 well since a single well producing at capacity could, in a short time, produce about one third of the pool reserves while reducing the reservoir pressure to the dewpoint pressure. It took the position that the Board should defer any decision on production, including primary depletion, from this pool until a unit agreement can be completed.

The Board considers the HBOG plant a suitable location for processing K-Pool production and believes that the technical matters connected with pool cycling can be adequately dealt with under the cycling application. The Board acknowledges that it is desirable that primary depletion be carried out in an equitable fashion for pools of this nature, however, it does not consider this to be sufficient reason for deferring the granting of the pipeline permit since it believes primary depletion could continue competitively until the dewpoint is reached. The Board will ensure optimum liquid conservation within the pool by requiring pressure maintenance and cycling of the pool at the dewpoint pressure.

F Pool

HBOG stated that the gas in place for the F Pool was 698 $10^6$ $m^3$ and that the current reservoir pressure was about 42 100 kPa. It proposed to produce from its 8-7 well on primary depletion for some 200 days at a rate of about 140 $10^3$ $m^3/d$ until the reservoir pressure was reduced to the fluid dewpoint pressure of 32 500 kPa. While it agreed the reservoir should be cycled after reaching that pressure, it believed the reservoir pressure was high enough to allow competitive primary depletion of the pool until then. HBOG stressed its desire to process its gas at its processing plant and noted the proposed pipeline to the 8-7 well could accommodate all F-Pool production if necessary. HBOG also noted Petro-Canada's plan for cycling the F Pool was only recently applied for and suggested cycling could take place with the gas being processed at two plants if the necessary agreements were in place. It believed those agreements could be made.

Petro-Canada stated it had filed a gas cycling application for the F Pool with the Board where F-Pool production would be pipelined to its proposed 4-31 gas plant. It believed unitization agreements were prerequisite to primary depletion to ensure equitable drainage and stated that it would be premature to proceed prior to full consideration by the Board of its cycling scheme and gas processing plant proposals. In support of this view, it argued that the 8-7 production had not been included in the original design gas throughput of the HBOG plant. It contended the utilization of its existing compression and other facilities at its 4-31 battery would provide not only economic advantages but also necessary cycling scheme operating flexibility. It stated that operating a cycling scheme in a small reservoir such as the F Pool would be difficult with two operators, each with its own processing facility, but agreed with HBOG it was technically feasible.

Texaco, with an interest in the 4-8 and 5-8 wells, supported the Petro-Canada gas cycling scheme and said that unitization should occur before any primary production takes place. It expressed concern that the pool cycling scheme would not be operated by a common operator but agreed with HBOG that it was possible to process production at two locations.

Amoco stated that the F Pool is a near-critical gas condensate reservoir requiring gas cycling to effect optimum liquid recovery and that Petro-Canada, as the pool operator, could better control the injection and production rates and pressures to maximize sweep efficiency and product recovery with the HBOG 8-7 well tied into that proposed cycling scheme. Amoco stated a pipeline from 9-1 to 8-7 would result in duplication of facilities within an environmentally sensitive area if Petro-Canada's applications proceed. It also indicated that approval for the 8-7 tie-in should not proceed prior to consideration of the Petro-Canada gas cycling and processing plant applications before the Board.

The Board notes the common concern of Petro-Canada, Texaco, and Amoco that early implementation of cycling is very important in the development of the pool. Furthermore, the pool is in an environmentally sensitive area between Dismal Creek and the Pembina River and therefore, there may be environmental as well as technical reasons why producing this pool would be more appropriately done through one pipeline and processing facility. Hence the Board does not consider the proposed pipeline to the F Pool appropriate at this time given the environmental, conservation, and economic concerns associated with the operation of more than one pipeline. Accordingly, it is not prepared to grant a permit to construct the pipeline from 9-1 to 8-7 until the earlier mentioned concerns have been addressed. Should voluntary unitization occur with the F-Pool gas committed to one or the other of the competing pipeline and gas plant systems, the Board would be prepared to issue the

appropriate permits, given that the environmental questions have been properly addressed. If unitization does not occur before the Board's consideration of the proposed Petro-Canada F-Pool gas cycling scheme and gas processing plant applications, then the Board would consider further representations respecting the pipeline following decisions on those proposals.

## 4 ECONOMIC, ORDERLY, AND EFFICIENT DEVELOPMENT OF THE AREA

HBOG indicated that about 80 per cent of the gas reserves to be gathered by its proposed pipelines belongs to HBOG or Dome Petroleum Ltd. and emphasized its right to recover and process its gas. It believed its proposed gathering system, following the approval of its gas plant, represented economic, orderly, and efficient development.

To evaluate whether the HBOG proposed pipelines constitute economic, orderly, and efficient development, the Board considered the Canterra and Amoco proposals. The Canterra proposal was to gather all or part of the Brazeau River - West Pembina area production, extract the produced liquids and transport the remaining dry sour gas to its Ram River gas plant via the Blackstone-Stolberg pipeline. The Amoco proposal included a Carbonate Bank gas cycling scheme, an enlarged Petro-Canada sour gas gathering system, and a second gas plant at the proposed Petro-Canada 4-31 gas plant site.

### 4.1 Canterra Proposal

Canterra stated that it had been approached by Brazeau River area operators regarding transportation to and processing of sour gas at its Ram River gas plant. Canterra estimated the capital costs of transporting production from a central location in the area (assumed to be 2400 $10^3$ $m^3/d$) to be \$15.4 million for the necessary pipeline and compression facilities. It said the Ram River plant has sufficient capacity to process additional gas and its proposal would result in advantages such as saving the capital cost of new sulphur recovery equipment, reduced $SO_2$ emissions and the utilization of existing facilities. Amoco outlined the additional facilities needed should Brazeau River area gas be processed at Ram River. These consisted of a gathering system (\$14 million), a liquid extraction facility (\$41 million), compression facilities (\$9 million), and a return residue gas line from the Nova system to the proposed Petro-Canada site for the gas cycling schemes (\$5 million). Amoco supported Canterra's view that Ram River processing results in environmental and sulphur handling benefits. Further, Amoco suggested HBOG's estimated cancellation charges of \$20 million, should its plant not proceed, may be high.

Concerning the liquid extraction facility, Canterra said preliminary calculations show that liquids can be extracted from a sour gas stream prior to sweetening and meet the necessary product specification required by the Amoco NGL gathering system servicing the area.

Canterra stressed the preliminary nature of its proposal and said that it may also be considered complementary to developments currently underway.

The Board agrees that a downsized Canterra proposal may be complementary to the HBOG development, but is concerned that a full scale proposal would require an extensive gathering system, processing and transportation fee negotiations, a transmission pipeline to Canterra's Blackstone dehydration facility, the design of a liquids extraction plant, and a return residue gas pipeline, all in addition to the consequent deferral, if not permanent abandonment, of the approved HBOG processing plant. The Board notes that the Canterra proposal is prelimary in nature and therefore, in terms of area development, does not see it as a reason to withold approval of the HBOG pipelines.

### 4.2 Amoco Proposal

Evidence submitted by Amoco showed a tentative proposal for development of the Carbonate Bank. The proposal contemplates the gathering of production from the 6-29, 7-34, 10-2, 7-10, and 13-12 wells and transporting the gas to a twinned Petro-Canada 4-31 gas plant via an enlarged gas gathering system. It contended that taking the production to the proposed Petro-Canada plant would provide for better liquid recovery in the Carbonate Bank area and would minimize not only the length of pipelines in an environmentally sensitive area but also pipeline costs. It also contended that enough is known about the Carbonate Bank reservoir continuity, from the pressure drawdown due to the 13-12 blowout, to warrant immediate gas cycling; and stated the view that primary Carbonate Bank production would result in the loss of gas liquids as the reservoir was currently at or marginally above the dewpoint pressure of the reservoir fluid. It stated that, under these circumstances, primary Carbonate Bank production should not be approved.

While Petro-Canada said production from the Amoco proposal was not included in its gas plant design, it urged the Board to evaluate the necessity of the lateral from 3-32 to 6-29 after the hearing of the proposed Petro-Canada 4-31 gas plant. It suggested that the lateral may not be justified when the 7-34 and 6-29 wells are considered alone. However, it also said it would not be applying to expand or twin its proposed plant for some time.

HBOG stated that initially it would not require production from other existing or proposed Carbonate Bank wells for its plant but emphasized that production from the 7-34 and 6-29 wells was required to utilize its plant effectively. It stated its development plan for the 7-34 well allowed for initial primary depletion to the reservoir fluid dewpoint pressure after which it would evaluate gas cycling prospects. It undertook to re-evaluate the dewpoint pressure of the reservoir fluid and to not produce past that point. It stated that production from the reservoir would provide additional information to continue evaluation of the Carbonate Bank.

Concerning the Amoco proposal, the Board notes that the Petro-Canada proposed plant does not have sufficient capacity for this development and the proposed pipeline gathering system would also require re-design. The Board notes that Petro-Canada did not contemplate the processing of the reserves in the wells proposed by Amoco at its facility and has not filed an application to expand its plant. Therefore, the Board does not see these as reasons to withold approval of the HBOG proposal.

## 5 SAFETY

HBOG stated that its pipelines were designed in accordance with the Pipeline Act and Regulations and Canadian Standards Association standard CSA Z184-M1979. It said that high/low pressure sensing, fail-close sectionalizing emergency shut down valves would be placed along the proposed sour gas pipelines to limit the potential $H_2S$ release volumes. Using the calculation method described in ERCB Interim Directive ID 81-3, the pipelines would be classified as Level 3 sour gas facilities. HBOG also said it was completing its emergency contingency plan for the area.

The Exposures Committee questioned HBOG about the safety features of its proposal, such as block valve spacing as well as its emergency contingency plan.

The remaining interveners did not question HBOG about safety-related matters.

The Board is satisfied that the pipelines have been designed using the appropriate codes and standards and believes HBOG can operate the proposed system safely. Furthermore, it considers the risk associated with the proposed development to be low because of the limited permanent population of the area.

## 6 DECISION

The Board approves Applications 810924, 810925, 810926, and 820251 of HBOG subject to the following:

<u>810924</u>

1. The permit to construct the applied-for pipeline between 6-29-47-11 W5M and 7-34-47-12 W5M is conditional upon the filing of an agreement detailing the completion of DSU pooling for the 6-29 well.

2. The Board defers its decision for the portion of the pipeline between 9-1-48-14 W5M and 8-7-48-13 W5M until it has considered the proposed Petro-Canada gas plant and F-Pool cycling scheme following which the Board would be prepared to reopen the hearing with respect to that portion of the pipeline to consider further evidence regarding the need for the line.

810925

1. The permit to construct the applied-for pipeline between the well in 6-31-46-14 W5M and the main gathering line at 15-8-47-14 W5M is conditional upon the filing of an agreement detailing the completion of DSU pooling for the 6-31 well.

2. Similarly, the permit to construct the 15-9-47-14 W5M well tie-in is conditional upon the completion of DSU pooling for the well.

The permits will be issued upon receipt of approval of the Minister of the Environment with respect to environmental matters.

ISSUED at Calgary, Alberta, on 14 July 1983.

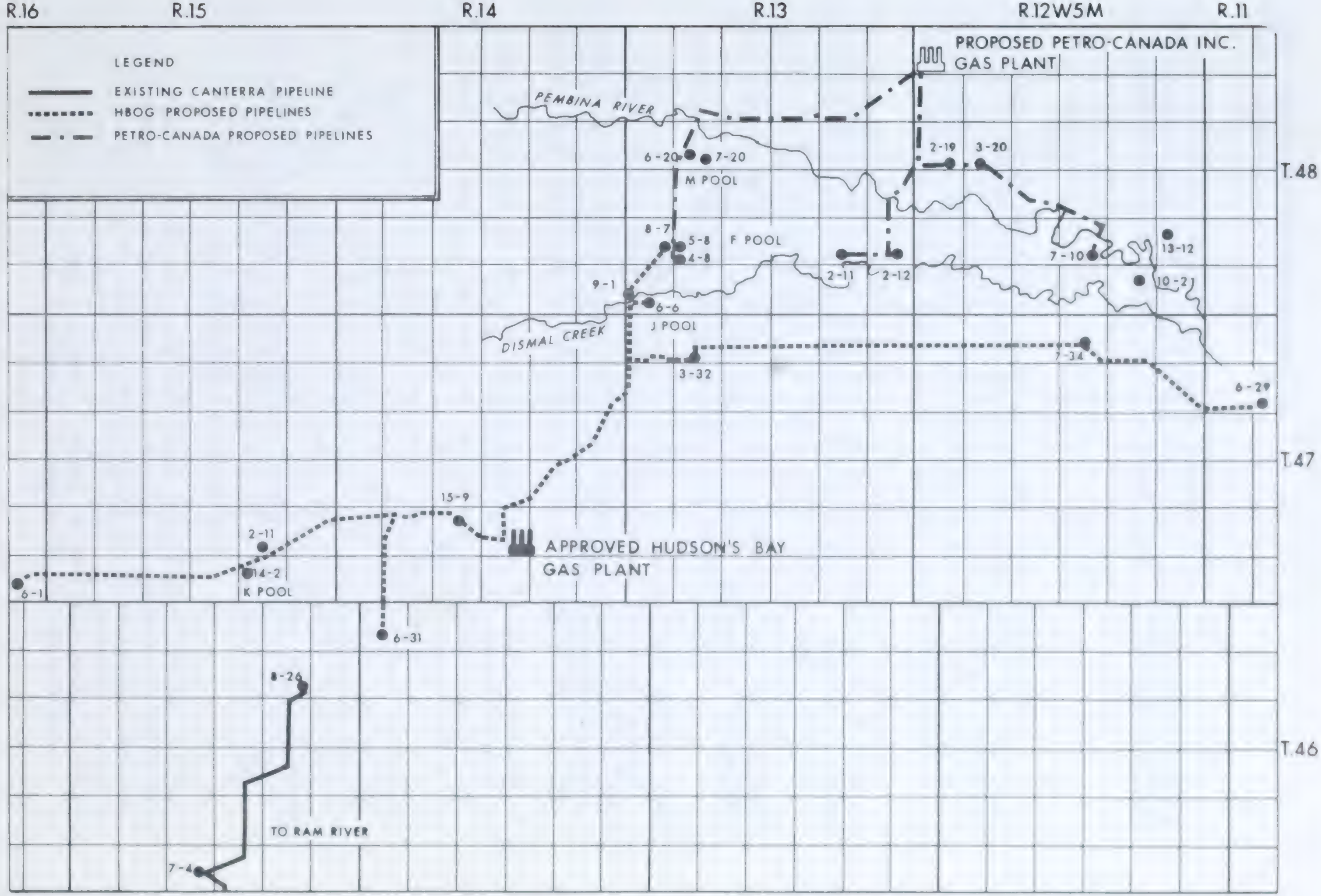
ENERGY RESOURCES CONSERVATION BOARD

V. E. Bohme, P.Eng.
Board Member

C. J. Goodman, P.Eng.
Board Member

J. A. Bray, P.Eng.
Acting Board Member

| Principals and Representatives (Abbreviations Used in Report) | Witnesses |
|---|---|
| Hudson's Bay Oil and Gas Company Limited (HBOG)<br>F. M. Saville<br>R. A. Neufeld | J. R. Moore, P.Eng.<br>P. J. Grant, P.Eng.<br>G. Mott<br>Dr. G. R. Besserer, P.Eng.<br>E. J. Muchowski, P.Eng. |
| Amoco Canada Petroleum Company Ltd. (Amoco)<br>S. E. Lipton | R. G. Nicholls, P.Eng.<br>J. D. Griffith, P.Eng.<br>R. B. Arnold, P.Eng. |
| Canterra Energy Ltd. (Canterra)<br>S. Carscallen | J. D. Kingsbury, P.Eng.<br>B. R. Pardy, P.Eng.<br>L. B. Haggar, P.Eng., of Haggar Engineering Ltd. |
| Home Oil Company Limited (Home)<br>L. L. Conner | |
| Pembina Resources Limited (Pembina)<br>A. Leewenburgh | |
| Petro-Canada Inc. (Petro-Canada)<br>D. O. Sabey, Q.C.<br>B. K. O'Ferrall | F. J. Bagley, P.Eng.<br>P. H. Verity, P.Eng.<br>G. A. Reitzel, P.Eng. |
| Shell Canada Resources Limited (Shell)<br>J. D. Courtright | W. D. McQuitty, P.Eng.<br>D. M. Bulger, P.Eng. |
| Texaco Canada Resources Ltd. (Texaco)<br>W. F. Muscoby | B. C. Winger, P.Eng.<br>K. Braaten, P.Eng. |
| Her Majesty the Queen in the Right of Alberta (Crown)<br>A. R. Watson | |
| Pembina Area Sour Gas Exposures Committee (Exposures Committee)<br>D. P. Mallon | |
| Energy Resources Conservation Board staff<br>D. A. Holgate<br>G. C. Dunn, P.Eng.<br>H. W. Knox, P.Eng. | |




HBOG PROPOSED PIPELINES. Brazeau River - West Pembina Area

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

PUBLIC INQUIRY TO CONSIDER POTENTIAL CONFLICTS
BETWEEN DEVELOPMENT OF SOUR GAS RESERVES — Inquiry Report D 83-12
AND RESIDENTIAL DEVELOPMENT IN THE OKOTOKS AREA — Proceeding 821137

## 1 SUMMARY


The Energy Resources Conservation Board was requested by the Lieutenant Governor in Council to investigate how potential conflicts between the development of the sour gas reserves in the Okotoks area and residential development might be minimized. The Board held an inquiry in March 1983 at which 18 persons and groups participated.

There was general agreement that at the present time there are no serious conflicts between sour gas operations and residential land use in the rural areas nor near Okotoks and High River. However, sour gas reserves in the general area are extensive and have been developed relatively slowly, with the result that some areas are virtually undepleted in spite of the fact that gas production has been occurring for over 20 years. It is apparent that unless the rate of depletion increases there will be land-use conflicts in the future.

The primary area of future conflict would be between relatively dense residential development and sour gas operations. There was general agreement by all participants that the best means of minimizing that conflict would be by depleting the sour gas reserves as quickly as possible, and deferring further residential development in the area.

A major impediment in the way of rapid depletion is the difficulty of marketing the gas that would be produced. If that constraint were eliminated and markets assured, the Board believes that essentially all of the gas could be produced in about 20 years. On the other hand, if the current situation continues, gas exploration and development will be protracted with the result that either conflicts with residential development will occur in the future or some of the sour gas reserves will not be recovered. The Board believes that action should be taken to avoid either of those possibilities and recommends that amendments be made to the Oil and Gas Conservation Act which would permit, with the approval of the Lieutenant Governor in Council, the Board to require purchasers to accept delivery of gas resulting from sour gas produced in the area.

The Board understands that the Municipal Districts of Foothills and Rockyview and the Calgary Regional Planning Commission currently have policies in place that restrict subdivision of agricultural land for country residential subdivisions in the area. If those policies are closely adhered to, then the second means of avoiding conflict between sour gas operations and residential development can be achieved.

Some of the participants contended that it would be unfair to defer indefinitely residential development or other land-use activities in order that sour gas reserves might be recovered at some future date. The Board generally agrees with that argument and plans to investigate imposing time constraints on exploration, development, and production where it is apparent that conflicts could arise in the relatively near future. The specific case referred to at the inquiry was an area bordering on the southeast corner of the current boundary of Calgary and which is a potential area for future annexation.

Participants contended, and the Board agrees, that conflicts can also be minimized by ensuring the safety of sour gas operations in relation to nearby residences. Current requirements placed on the industry provide for those safety measures but the Board plans to incorporate further refinements to its safety policies to provide more involvement of nearby residents as suggested at the inquiry.

Participants identified gaps, inconsistencies, lack of co-ordination, conflicting decisions, etc. in the current regulatory systems for sour gas operations and land-use planning. The Board agrees that the current system requires improvement and recommends that a liaison committee be established for this purpose. Membership of the committee should include senior representatives from Municipal Affairs, (especially the Alberta Planning Board and the Local Authorities Board) the regional planning commissions, and the ERCB. The Board also plans to convene meetings with the Calgary Regional Planning Commission, the City of Calgary, and the Municipal Districts of Foothills and Rockyview to review the special circumstances that exist in the general Okotoks area.

## 2 INTRODUCTION AND BACKGROUND

### 2.1 Reason for the Inquiry

The inquiry was initiated in response to Order in Council 695/82 dated 30 June 1982, in which the Lieutenant Governor in Council, pursuant to section 22 of the Energy Resources Conservation Act, requested the Energy Resources Conservation Board, in conjunction with its consideration of an anticipated application for approval of a gas processing plant in the Okotoks area, to make inquiries into and report on:

- how potential conflicts between the development of the sour gas reserves in the area and residential development may be minimized, and

- any other matters that may be relevant.

## 2.2 The Extent of the Problem

Figure 1 shows the location of sour gas pools and plants in the Calgary region. In immediate proximity to the Calgary city boundary are the Crossfield and Okotoks-Crossfield pools lying to the north and east, and southeast respectively.

Table 1 describes the sour gas plants in the Calgary region in terms of operator, commencement of operations, hydrogen sulphide ($H_2S$) content of the inlet gas, field source, capacity, and gas reserves that the plants process. The table reveals that unless production rates are accelerated, potential conflicts between sour gas reserves and urban development in the Calgary region will likely affect other areas besides Okotoks at some time in the future as the boundaries of Calgary and the towns in the regions continue to expand.

The Petrogas and Canterra sour gas plants located immediately northeast of Calgary and east of Okotoks, respectively, process gas with an average $H_2S$ content of some 35 per cent.

## 2.3 Study Area

The study area for the inquiry was the Okotoks area outlined in Figure 1 and shown in more detail in Figure 2, which depicts:

- the proven and potential extent of sour gas areas and related production facilities, and

- urban and rural areas in proximity to sour gas facilities.

## 2.4 Existing Land Use

Existing land use in the inquiry area is shown in Figure 3, which was submitted to the inquiry by Makale & Kyllo Planning Associates Ltd. as part of its study of land use and sour gas in the Okotoks-High River area.

Most of the land area is agricultural with a number of rural residential and small holdings between Calgary and Okotoks. An area of environmentally sensitive land is identified south of Calgary along the Bow River and recreational facilities are located along the river valleys; in particular, the Highwood River which joins the Bow River in the centre of the study area.

There are three main urban centres in the region: Calgary, Okotoks, and High River. The urban industrial areas are generally located east of the residential areas. A number of hamlets are located adjacent to the railway lines which converge on Calgary.

The rural lands are administered by the Municipal District of Rockyview in the northern part and by the Municipal District of Foothills in the southern part of the inquiry area.

TABLE 1 SOUR GAS PLANTS - CALGARY REGION

| 1<br>Operator/ Plant Name | 2<br>Commenced Operations | 3<br>Fields and Formations | 4<br>Ave. $H_2S$ Conc. in Inlet Gas<br>% | 5<br>Annual* Inlet Volume<br>$10^6 m^3$ | 6<br>1982 Production<br>$10^6 m^3$ | 7<br>Est. Rmng. Recoverable Reserves<br>$10^3 m^3$ | 8<br>Column 7 / Column 6 |
|---|---|---|---|---|---|---|---|
| North | | | | | | | |
| Home/Carstairs-Crossfield | 1960 | Carstairs-Rundle<br>Crossfield-Rundle | 1 | 3 598 | 1 356 | 10 630 | 7.8 |
| Petrogas/ Crossfield | 1961 | Crossfield<br>-Crossfield<br>-Rundle | <br>35<br>1 | 3 281 | 1 358 | 16 216 | 11.9 |
| Amoco/ Crossfield East | 1965 | Crossfield E.<br>-Crossfield | 35 | 1 872 | 785 | 11 206 | 14.3 |
| Dome/Lone Pine Ck. | 1966 | Lone Pine Ck.<br>-Crossfield | 15 | 765 | 247 | 3 290 | 13.3 |
| Cdn.Sup./Lone Pine Ck. | 1971 | Lone Pine Ck.<br>-Crossfield | 14 | 360 | 126 | 1 547 | 12.3 |
| Sub-Total | | | | 9 876 | | 42 899 | |
| West | | | | | | | |
| Shell/Jumping Pound | 1951 | Jumping Pound-Rundle<br>Jumping Pound W-Rundle | 4<br>6 | 2 651 | 2 088 | 45 188 | 21.6 |
| PCP/Morley | 1980 | Morley-Rundle | 7 | 103 | 28 | 382 | 13.6 |
| Petro Canada/ Wildcat Hills | 1961 | Wildcat Hills-Rundle | 4 | 1 286 | 457 | 9 759 | 21.4 |
| Phillips/Salter | N/A | Salter-Rundle | 16 | 216 | - | 867 | - |
| Shell/Burnt Timber | 1970 | Burnt Timber-Cross.<br>Hunter V.-Rundle<br>Wildhorse Ck-Rundle<br>Panther River-Rundle | 11 | 1 318 | 1 039 | 9 544 | 9.2 |
| Sub-Total | | | | 5 574 | | 65 670 | |
| South and Southwest | | | | | | | |
| Canterra/Okotoks | 1959 | Okotoks-Crossfield | 35 | 358 | 244 | 11 819 | 48.4 |
| Esso/Quirk Ck. | 1971 | Quirk Ck.-Rundle | 10 | 926 | 343 | 2 707 | 7.9 |
| Western Decalta/ Turner Valley | 1933 | Turner V.-Rundle | 2 | 411 | 252 | 7 002 | 27.8 |
| Sub-Total | | | | 1 695 | | 21 528 | |
| TOTAL | | | | 17 145 | | 130 987 | |

* Daily approved rate x 365 days

Source: ERCB Records

## 3 POTENTIAL CONFLICTS

The current primary land-use activities in the general Okotoks area include agricultural operations, recreational activities, urban residential development in the towns, and country residential development in the rural areas. Sour gas operations in the area must co-exist with those activities and may have an impact on them. The purpose of the inquiry was to investigate the extent of potential land-use conflicts and to explore how they might be minimized.

The participants, as outlined in Appendix A, generally agreed that currently there are no serious land-use conflicts and that by adopting appropriate policies future conflicts can be avoided or minimized. The following suggestions were made as a means of preventing potential conflicts:

- Sour gas resources in the area be identified and produced as quickly as possible.
- Residential development in the area be delayed until the sour gas reserves have been depleted.
- The safety of local residents be ensured.
- The interests of both surface owners and mineral owners be recognized and treated fairly.
- The activities and policies of the ERCB and the municipal planning authorities be co-ordinated as they relate to sour gas and land-use planning.

The Board agrees largely with the foregoing proposals and in the following sections considers each in detail.

## 4 EXPEDITIOUS DEPLETION OF SOUR GAS RESERVES IN THE AREA

There was general agreement by all participants that one of the most important means of avoiding future land-use conflicts would be to ensure that the sour gas reserves in the area are delineated and recovered as quickly as possible. That objective could be achieved by ensuring that:

- exploration and delineation drilling takes place expeditiously in order to confirm or deny the presence of potential reserves,

- markets are available for gas that could be produced, and
- sufficient processing plant capacity is available.

The participants generally agreed that the need to have available markets for the gas was the primary factor in ensuring rapid depletion of the reserves. If markets are available, mineral owners have incentives to explore and test whether potential reserves are a reality. Owners of gas reserves that are not on production can proceed to arrange for plant processing capacity if markets are assured. Similarly, production programs can be established to ensure maximum withdrawal rates.

A further incentive to ensure expeditious depletion would be by limiting the time that production can take place where residential development is being deferred in favour of recovery of sour gas reserves. This approach was suggested for the area which is adjacent to the current eastern boundary of Calgary and between the Crossfield and Okotoks fields shown in Figure 1.

Since expeditious depletion of the sour gas reserves is fundamental to avoiding potential land-use conflicts and since gas markets are an essential element, the Board has considered how markets can be ensured. Some participants at the inquiry indicated that normal voluntary arrangements would be sufficient, whereas others contended that specific action would have to be taken, particularly having regard for the substantial volumes of gas that are currently shut-in. The Board has considered each of these alternatives and has concluded that under the foreseeable gas marketing environment, the voluntary alternative will not be fully effective. Indeed, experience over the last few years has demonstrated the lack of progress in ensuring the rapid depletion of sour gas pools in the Okotoks area. The Board is convinced that the only way in which rapid depletion can be achieved is by making special arrangements for the marketing of the gas. The Board recognizes that the industry at large is suffering from limited gas markets but believes there is a special urgency with respect to marketing of sour gas reserves in the Okotoks area. The impact on total markets of providing special consideration for such gas is almost negligible since it would represent only some 0.5 per cent of the current total production.

## 5 DEFERMENT OF RESIDENTIAL DEVELOPMENT

The second most important action to avoid land-use conflicts between sour gas operations and residential development would be to defer residential development until the sour gas reserves in the area have been depleted. The Board understands that the policies of the

Municipal Districts of Foothills and Rockyview, as well as those of the Calgary Regional Planning Commission, are compatible with that objective in as much as they favour agricultural uses over small acreage residential land use. As a consequence, the expansion of the current base of country residential subdivisions appears to be, at least for the present, substantially limited.

The deferment of rural residential development in the area is clearly a planning matter. It appears to the Board to be desirable for the land-use plans that have been or will be developed in the future to give full recognition to the sour gas reserves and the potential conflict that exists between development of those reserves and other land uses such as residential development.

## 6 SAFETY OF LOCAL RESIDENTS

The Bow North Surface Rights Association and the Committee for Toxic Pollutant Controls were particularly concerned about the safety aspects of sour gas operations as they might affect local residents. The Board agrees that safety must be ensured if other land uses are to be compatible with sour gas operations. Minimizing the number of people near such operations assists in that objective but is not sufficient. Current safety measures include special equipment facilities, special operating practices, additional monitoring, specified setback distances, and emergency response plans. Suggestions made at the inquiry pertained primarily to refinements in the response plan procedure and, in particular, the involvement of local residents in the development of the plan. The Board supports that suggestion and plans to implement it.

## 7 PROTECTION OF THE INTERESTS OF SURFACE OWNERS AND MINERAL OWNERS

Some of the participants contended that it would be unfair to defer indefinitely residential development or other land-use activities in order that sour gas reserves might be recovered at some future date. The Board appreciates the concerns of the surface owner and agrees that deferral of surface development is only justified if action is being taken to recover the sour gas reserves. Indeed, it is that specific reasoning that leads the Board to conclude that markets should be ensured so that development and exploitation of the sour gas reserves can proceed expeditiously. Fortunately, the evidence suggests that there is a reasonable time span in the Okotoks area which would permit development and depletion of the sour gas reserves prior to the requirement for residential development on those lands. Where it is obvious that land-use conflicts are relatively near-term

(eg. the area east of the current boundaries of Calgary shown in Figure 1), the Board believes that in order to be fair to all parties, it would be necessary to establish the period under which exploration and development should be permitted. In order to arrive at rational policies for these cases, it would be necessary to involve both the planning authorities as well as the ERCB.

In addition to improved government liaison, the Board believes that oil and gas operators should take a more active part in land-use matters and should make their views known at subdivision and annexation hearings which might affect their operations.

## 8 CO-ORDINATION OF THE ACTIVITIES AND POLICIES OF THE ERCB AND THE MUNICIPAL PLANNING AUTHORITIES AS THEY RELATE TO SOUR GAS AND LAND-USE PLANNING

Participants identified gaps, inconsistencies, lack of co-ordination, conflicting decisions, etc. in the current regulatory system. Unfortunately, the information provided to the inquiry is not complete since it only included one municipal authority, the City of Calgary. The views of the Calgary Regional Planning Commission and the municipal districts are not known, although the Board has been advised that those authorities would wish to meet with the Board in due course. The Board welcomes that suggestion and plans to take advantage of the offers following the issuance of this report.

The Local Authorities Board forwards to the ERCB annexation proposals, notices of hearings, and decisions. Some planning commissions also refer annexation proposals to the Board for comment on setback distances. The current statutory provisions require planning bodies to forward applications for subdivisions that are located near sour gas facilities to the Board for its recommendations. The Board's assessment process is related to setback distances rather than the broader issue of the appropriateness of the particular land use being considered.

The Board generally agrees that the present system has inadequacies. Makale & Kyllo Planning Associates Ltd. proposed a revision to the system which would, in effect, make the ERCB the dominant authority in land-use matters where sour gas operations occur. The Board does not subscribe to that approach but rather supports the concept of the municipal planning bodies and the ERCB working co-operatively to solve existing problems. In fact, the issues encompass more than the

development of sour gas reserves and in the Board's view warrant the establishment of a special committee composed of senior representatives from Municipal Affairs, especially the Alberta Planning Board and the Local Authorities Board, and from the regional planning commissions and the ERCB to review the various issues. With respect to the specific Okotoks area, the Board believes the local municipal authorities and the ERCB should meet and review the problems identified at the inquiry with the general objective of taking action that would avoid future potential conflicts in land-use planning. It may well be necessary for the municipal and ERCB representatives to subsequently meet with the sour gas industry to review policies, plans, etc. that have been developed. The Board undertakes to initiate those meetings.

DATED at Calgary, Alberta, on 29 July 1983.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

V. E. Bohme
Board Member

N. Strom
Board Member

APPENDIX A

## THOSE WHO APPEARED AT THE INQUIRY

| Principals and Representatives | Witnesses |
|---|---|
| Alberta and Southern Gas Co. Ltd.<br>T. Sullivan<br>R. Pepper | |
| Amerada Minerals Corporation of Canada Ltd.<br>A. S. Hollingworth<br>R. Thompson | M. Meghani, P.Eng. |
| Bow North Surface Rights Association<br>S. Pier | S. Pier<br>D. Thomas<br>A. McElroy<br>W. Fairbrother<br>of Municipal District of Rockyview |
| City of Calgary<br>E. C. Brown | E. C. Brown |
| Canadian Occidental Petroleum Ltd.<br>A. L. McLarty<br>B. de Jonge | G. Simpson, P.Eng.<br>J. Hofbauer, P.Eng.<br>R. H. Orthlieb, P.Eng.<br>G. Brown*<br>D. Boyd*<br>*of Western Research and Development Ltd. |
| Canadian Petroleum Association<br>R. J. Lane | W. K. Ross, P.Eng. |
| Canadian Superior Oil Ltd.<br>R. W. Riegert | A. Shklanka, P.Eng.<br>Dr. E. Kustan, P.Eng.<br>N. Dibble, P.Eng. |
| Canterra Energy Ltd.<br>W. J. Major<br>P. Major | L. E. Fenwick, P.Eng.<br>E. Plumm, P.Eng.<br>J. Carmichael, P.Eng.<br>D. McCoy |

APPENDIX A (cont'd)

THOSE WHO APPEARED AT THE INQUIRY

| Principals and Representatives | Witnesses |
|---|---|
| Committee for Toxic Pollutant Controls<br>D. Evans | M. MacKenzie |
| Goldenview Farms Ltd.<br>S. Carscallen | |
| Town of High River<br>Mrs. Dougherty | Mrs. Dougherty |
| J. M. Huber Corporation<br>S. Collins, P.Eng. | S. Collins, P.Eng. |
| Makale & Kyllo Planning Associates Ltd.<br>D. Makale, MCIP<br>L. Kyllo, MCIP | D. Makale, MCIP<br>L. Kyllo, MCIP<br>D. Mutrie, MCIP |
| Mitchell Energy Corporation<br>D. J. Hartmann<br>H. K. Milhoan | A. Shea, P.Eng. |
| F. J. Ollerenshaw<br>F. R. Foran<br>D. Wright | R. Ollerenshaw |
| N. L. Rocher | |
| Her Majesty the Queen in Right of Alberta<br>A. Watson<br>G. Roy | |
| Energy Resources Conservation Board staff<br>D. A. Holgate<br>Dr. W. R. Towle<br>W. J. Schnitzler, P.Eng.<br>J. R. Nichol, P.Eng. | J. D. Dilay, P.Eng.<br>W. A. Warren, P.Eng. |

The Village of Blackie, The Gladys United Church Congregation, Bounty Developments, and Gannon Bros. Energy Limited tendered submissions but did not appear at the inquiry.

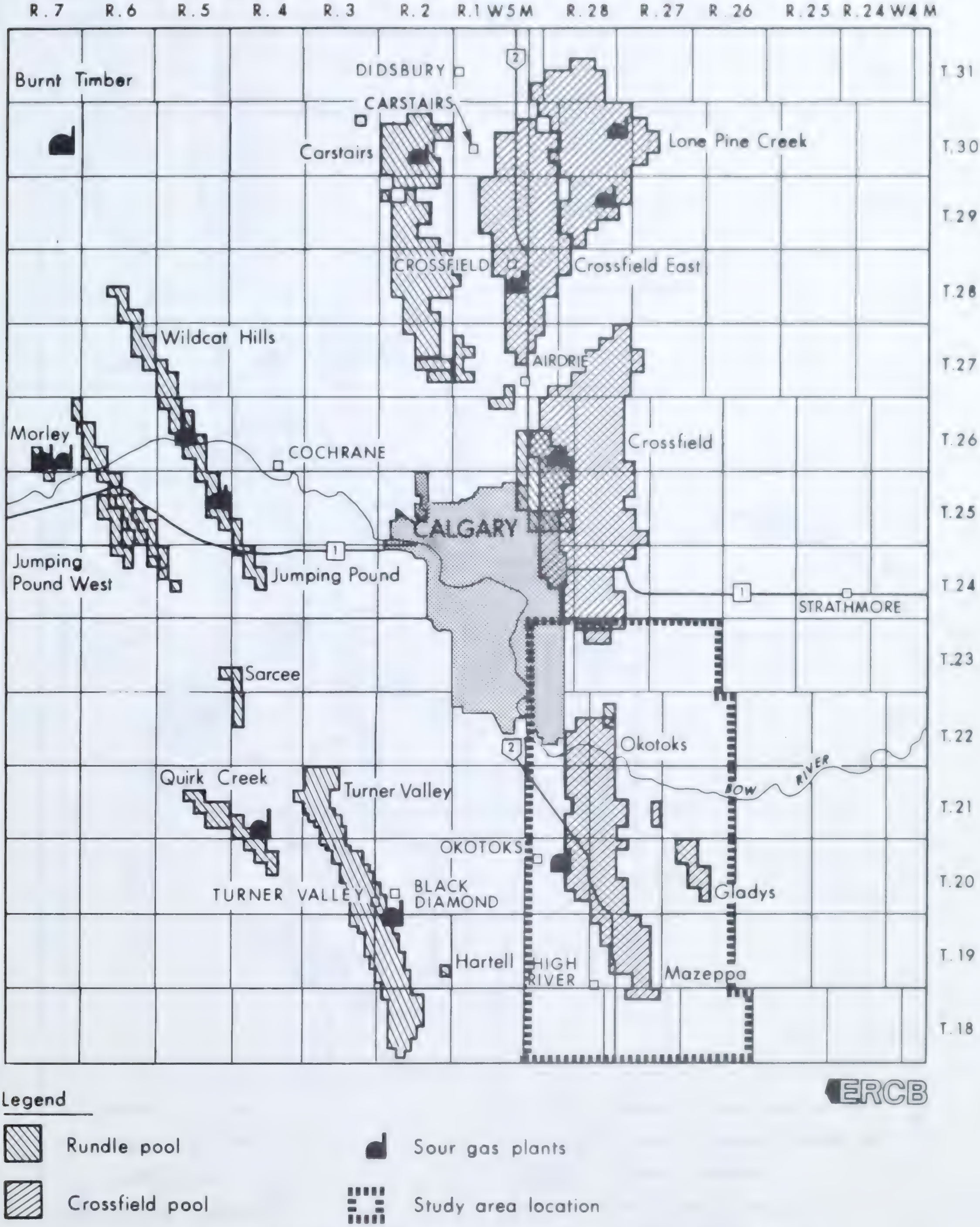



FIGURE 1 SOUR GAS POOLS & PLANTS IN THE CALGARY REGION

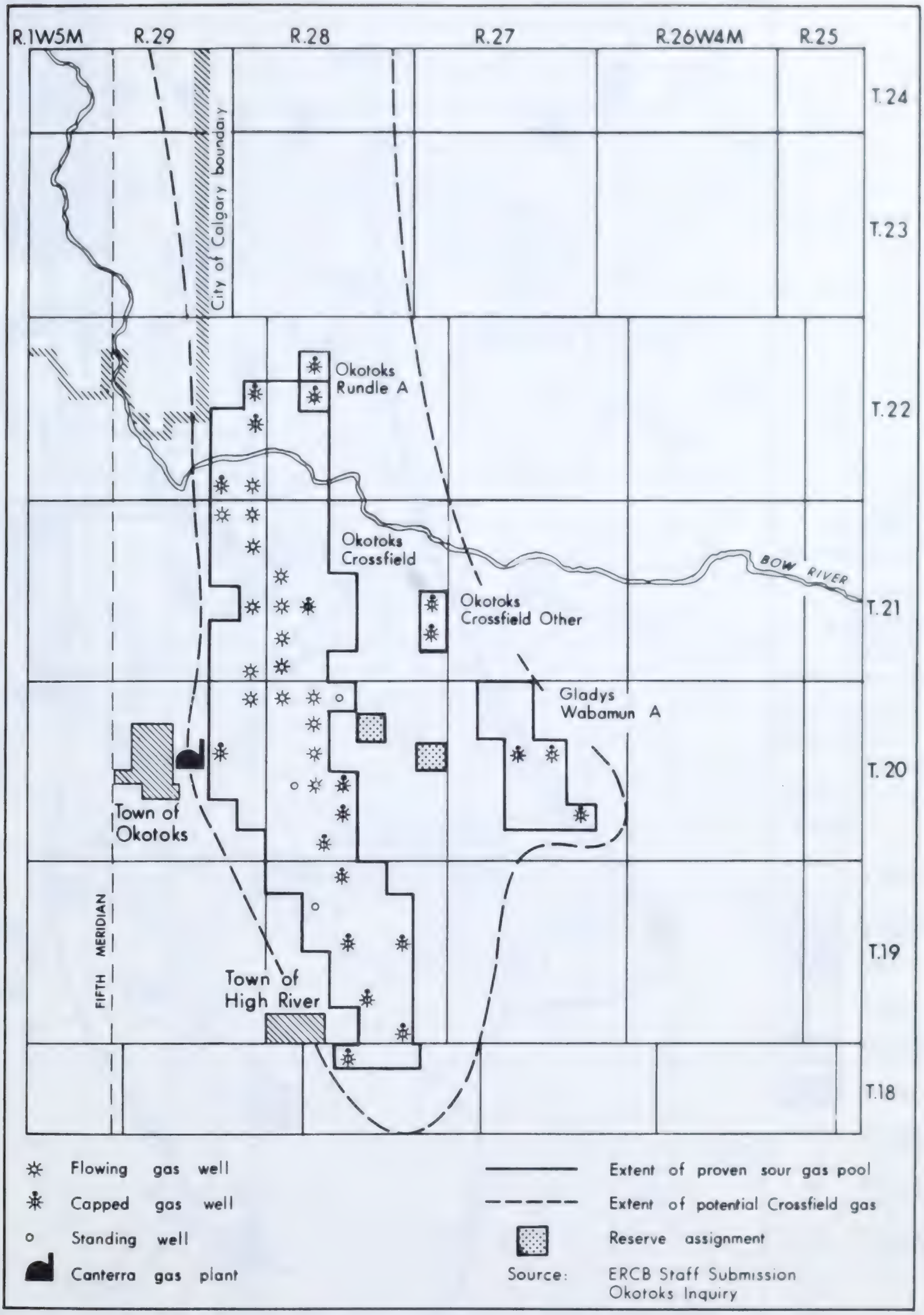
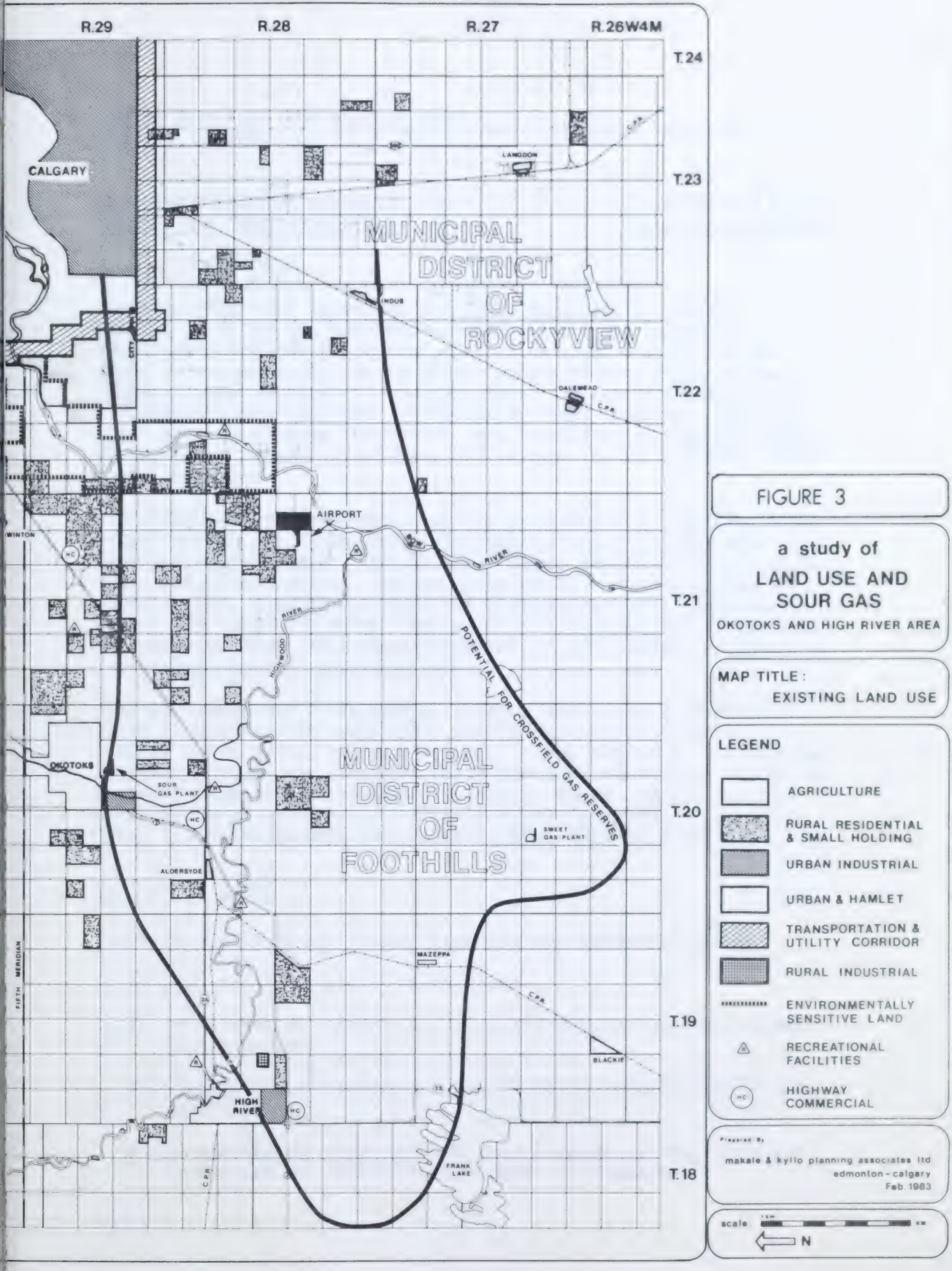



FIGURE 2. THE OKOTOKS AREA. Sour Gas Pools, Wells and Potential Gas Reserves Area



R.29
R.28
R.27
R.26W4M
T.24
T.23
T.22
T.21
T.20
T.19
T.18
CALGARY
LANGDON
INDUS
DALEMEAD
C.P.R.
MUNICIPAL DISTRICT OF ROCKYVIEW
AIRPORT
BOW RIVER
HIGHWOOD RIVER
POTENTIAL FOR CROSSFIELD GAS RESERVES
OKOTOKS
SOUR GAS PLANT
SWEET GAS PLANT
MUNICIPAL DISTRICT OF FOOTHILLS
ALDERSYDE
MAZEPPA
BLACKIE
HIGH RIVER
FRANK LAKE
FIFTH MERIDIAN
FIGURE 3
a study of
LAND USE AND SOUR GAS
OKOTOKS AND HIGH RIVER AREA
MAP TITLE:
EXISTING LAND USE
LEGEND
AGRICULTURE
RURAL RESIDENTIAL & SMALL HOLDING
URBAN INDUSTRIAL
URBAN & HAMLET
TRANSPORTATION & UTILITY CORRIDOR
RURAL INDUSTRIAL
ENVIRONMENTALLY SENSITIVE LAND
RECREATIONAL FACILITIES
HIGHWAY COMMERCIAL
Prepared By
makale & kyllo planning associates ltd
edmonton - calgary
Feb. 1983
scale
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ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

CANADIAN OCCIDENTAL PETROLEUM LTD. — Decision D 83-13
OKOTOKS GAS PROCESSING PLANT — Application 820346

## 1 INTRODUCTION

Canadian Occidental Petroleum Ltd. (Cdn. Oxy) applied, pursuant to section 26 of the Oil and Gas Conservation Act, for approval to construct a sour gas processing plant to be located at one of two sites in the southerly (Mazeppa) area of the Okotoks Field as shown in Figure 1. The applicant's preferred plant site is in section 3 of township 20, range 28, west of the 4th meridian (site B). Cdn. Oxy also requested that an alternative site located within the east half of section 35, township 19, range 28, west of the 4th meridian (site A) be considered.

The plant would be designed to process a maximum of 1.7 million cubic metres per day of raw gas containing approximately 35.5 per cent hydrogen sulphide ($H_2S$). Of the 835.1 tonnes per day (t/d) of sulphur contained in the raw gas, Cdn. Oxy proposes to recover a minimum of 98.3 per cent on an annual basis and 98.0 per cent on a quarterly basis. The remaining annual average 14.14 t/d of sulphur in the form of sulphur dioxide ($SO_2$) would be emitted to the atmosphere through an incinerator stack 90 metres in height.

The application was considered at a public hearing in High River on 11 to 15 April and 18 April 1983, with V. Millard, V. E. Bohme, P.Eng., and N. Strom, P.Eng., sitting. At the request of Cdn. Oxy and Goldenview Farms, the Board and participants in the hearing viewed the proposed plant sites, the nearby Goldenview Farms, and the subdivisions of Alderwood and Highview on the afternoon of 12 April 1983. A list of hearing participants may be found in Appendix A.

## 2 THE ISSUES

The Board considers the issues respecting the application to be

- the need for and size of the plant,
- environmental concerns and perceived negative economic impacts of the project,
- technical and economic considerations on sulphur recovery and plant siting,
- maintenance of adequate separation distances between sour gas facilities and residential and other developments,

- o emergency response planning, and
- o general benefits of the project on the local area and the province.

## 3 NEED FOR AND SIZE OF PLANT

### 3.1 Established and Potential Reserves

#### 3.1.1 Applicant's Views

Cdn. Oxy estimated that established producible raw gas from the Crossfield Pool in the Mazeppa area is 7.0 x $10^9$ $m^3$. It acknowledged the potential for additional reserves in areas flanking the main reservoir trend.

#### 3.1.2 Interveners' Views

Canterra stated that in the producing area served by its Okotoks plant, the Crossfield Formation has 4.088 x $10^9$ $m^3$ of remaining established reserves of producible raw gas. Canterra estimated the recoverable gas reserves to be 5 x $10^9$ $m^3$ to 6 x $10^9$ $m^3$ in the Mazeppa area and 1.2 x $10^9$ $m^3$ in Amerada's area to the north. Canterra indicated that perimeter areas, if developed, might contribute significant additional amounts of producible gas. This gives total remaining producible sour gas reserves in the area between Calgary and High River of between 10.3 x $10^9$ $m^3$ and 11.3 x $10^9$ $m^3$.

#### 3.1.3 Board's Views

The Board had instructed ERCB staff to update its estimate of sour gas reserves in the general southeast Calgary to High River area (Figure 2) in preparation for an earlier public inquiry[1] requested by the Lieutenant Governor in Council. That summary indicated established producible gas from the Okotoks Crossfield and Okotoks Rundle Pools to be 10.7 x $10^9$ $m^3$. The ERCB staff estimated a further reserve of 1.1 x $10^6$ $m^3$ in two other pools: Gladys Wabamun A and Okotoks Crossfield Other. The Board notes that there is general agreement that established producible raw gas reserves are approximately 10 to 12 x $10^9$ $m^3$. In addition, the Board estimates that the proven reserves

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1 Report to the Lieutenant Governor in Council <u>Public Inquiry to Consider Potential Conflicts Between Development of Sour Gas Reserves and Residential Development in the Okotoks Area</u>. ERCB Report D 83-12 Calgary, Alberta.

might increase by 50 per cent (5 to 6 x $10^9$ $m^3$) by drilling out marginal quality perimeter areas.

### 3.2 Plant Size in Relation to Reserves and Contracts

#### 3.2.1 Applicant's Views

Cdn. Oxy applied for a sour gas processing plant capable of processing 1700 x $10^3$ $m^3/d$. The plant was designed to accommodate all sour gas in the area that is not currently being produced to the Canterra plant, which Cdn. Oxy understood is operating at near its design capacity.

The applicant qualified its application by stating that while it had applied for 1700 x $10^3$ $m^3/d$, it would not build a plant with capacity in excess of the amount of gas for which it had reasonable assurances of sales contracts.

Cdn. Oxy pointed out that 1200 x $10^3$ $m^3/d$ was the minimum threshold size to justify construction and operation of this kind of plant. Currently, Cdn. Oxy has agreements with Pan-Alberta and Sherritt Gordon for the sale of gas from the Mazeppa area for about 150 x $10^3$ $m^3/d$ and 30 x $10^3$ $m^3/d$, respectively. Due to processing shrinkage this would require a plant capacity of about 360 x $10^3$ $m^3/d$ of raw gas.

The applicant stated it intends to pursue markets through various means including transferring contracts from other areas of the province to the Okotoks area. It believed that the contracts required for the 1700 x $10^3$ $m^3/d$ plant could be achieved solely through this mechanism.

Cdn. Oxy stated that it is in the public interest to deplete the reserves in the Okotoks area at the earliest possible time. It went on to state that its scheme would accomplish depletion much more rapidly than could be achieved by a number of smaller plants. Cdn. Oxy submitted that although increased processing capacity in the area would not ensure expeditious depletion of reserves unless a gas market is found, gas contracts would only follow after approval for processing capacity was in place.

#### 3.2.2 Interveners' Views

Canterra stated that the applied-for plant capacity is larger than that required to process gas in the Mazeppa area alone. With respect to the feasibility of bringing in other gas, particularly from Amerada's lands north of the Bow River and other owners' lands in the Gladys Field, Canterra referred to its understanding that in both instances the owners of the gas are not prepared to participate in the proposed Cdn. Oxy plant because the economics are unattractive.

Canterra stated that with respect to currently proven reserves, the above conclusion leaves only Mazeppa area gas to be processed at the proposed plant. Therefore, Canterra concluded that for the contracts that could be available for the extension into the Mazeppa area, the gas processing capacity needed is between 850 x $10^3$ $m^3/d$ and 1200 x $10^3$ $m^3/d$.

Canterra stated that with its existing processing capacity it can deplete its area in 20 years. It recognized that additional processing capacity would be needed for timely depletion of all sour gas reserves in the general area from Calgary to Mazeppa. It suggested that dependent on assumptions made regarding Amerada's reserves and faster depletion of Canterra's reserves, some increased capacity could be added at the existing Canterra plant.

Canterra stated that in 2 to 3 years, the reserves that are currently feeding its Okotoks plant will not use all of the plant's available capacity and that the underutilization will increase thereafter so that in 10 years it could supply the capacity required by Amerada. It stated that with the existing plant capacity, 75 to 80 per cent of the producible reserves held by Amerada could be depleted within 20 years.

Goldenview Farms stated that if there is no market for the gas, there is no need for a plant. It maintained from the evidence provided by Cdn. Oxy that there are currently only modest gas contracts in the area.

### 3.2.3 Board's Views

The Board concludes that the applied-for 1700 x $10^3$ $m^3/d$ capacity of the proposed plant is in excess of that required to produce the proven gas in the Mazeppa area as defined by Cdn. Oxy. However, the Board notes that there are other sour gas reserves in the area that cannot be produced in a reasonable time with the existing processing capacity in the area.

The Board believes that provision of adequate processing capacity to ensure early depletion of the reserves in the Okotoks area is highly desirable and is more important than the technical matching of reserves and gas processing capacity. This conclusion is supported by one of the Board's findings from its public inquiry into minimizing potential conflicts between development of sour gas reserves and residential development in the Okotoks area. In its report to the Lieutenant Governor in Council, the Board recommended that the government should provide the necessary authority through legislation to direct the purchase of gas under certain circumstances. One of these would be to attain early depletion of sour gas reserves near urban areas.

The Board views fewer larger plants as a better alternative than a multiplicity of smaller plants as the former generally provide greater overall sulphur recovery and therefore reduced $SO_2$ emissions. Hence, the Board concludes that the construction of a plant with sufficient capacity to process all the proven and potential sour gas reserves in the area which are not currently committed to the Canterra plant would be the best option. The Board accepts the Cdn. Oxy position that the minimum economic size for its plant would be not less than $1200 \times 10^3$ $m^3/d$. On the foregoing considerations, the Board would be inclined to approve the applied-for $1700 \times 10^3$ $m^3/d$ size but upon application by Cdn. Oxy would be prepared to reduce the approved inlet quantities to reflect reduced reserves available to the plant.

## 4 ENVIRONMENTAL CONCERNS AND PERCEIVED NEGATIVE ECONOMIC IMPACTS

The Board heard two interveners, Goldenview Farms and the CTPC, express concerns that they would be affected by various negative environmental and economic impacts, should the proposed plant be approved as applied for. The Board heard another intervener, Rio Frio Ranch, which believed there would be no negative environmental or economic impacts.

This section of the report discusses the major concerns of Goldenview Farms and the CTPC, the applicant's responses to those concerns and the Board's views and conclusions.

### 4.1 Goldenview Farms' Views

The Goldenview Farms submission dealt mainly with concerns respecting effects on cattle health and resulting effects on economic viability of its cattle operation. These detrimental effects were perceived to be caused by gas plant emissions on the soils, vegetation, and cattle in combination with the visual impact of the plant being in the immediate vicinity of Goldenview Farms. It stated that there is a widely held perception within the purebred cattle fraternity that cattle exposed to industrial emissions are less healthy or less fertile than non-exposed cattle. Indeed, Goldenview expressed its own concern regarding the possible reduction in fertility and overall productivity of its purebred breeding operation. It was Goldenview Farms' position that the proposed sour gas facility, located at either of the proposed sites, would be clearly visible to prospective cattle purchasers as they visited the farm. Goldenview Farms expressed fears that prospective purchasers visiting the farm would see the sour gas facility and would therefore be less likely to bid as high a price for its cattle. The result would be a threat to the economic viability of the Goldenview Farms operation.

## 4.2 CTPC's Views

The CTPC expressed concern that emissions from sour gas plants are reportedly responsible for health problems of residents living downwind from such facilities. The CTPC stated that since no evidence yet exists to prove or refute its concern, the proposed plant should be a zero-emitter or be as close to that goal as is technically feasible.

The CTPC stated that it believed there was a distinct possibility that Cdn. Oxy would request that the plant's water supply come from wells drilled in the area. It opposed the use of this source since it stated that there is not sufficient groundwater to supply the residents' needs.

The CTPC was also concerned that the location of the proposed facility at either site A or B would result in reduced property values in the area. The reduction in property values was perceived to be caused by the negative impact on the view, especially from the rural residential subdivisions of Alderwood and Highview, and by a reduction in the number of potential purchasers of property because many people would prefer not to live close to a sour gas facility.

The CTPC stated that other alternative sites would reduce impacts from the proposed plant. No alternative sites were identified by the CTPC and it did not explain how the impacts could be reduced by selecting a different site. The CTPC's contention was that siting would become a minor issue if the plant were designed to reduce emissions to a lower amount than would be allowed under the current requirements.

## 4.3 Applicant's Views

In response to Goldenview Farms' concerns, Cdn. Oxy stated that proximity to sour gas facilities would not result in any adverse impact on the fertility or general health of cattle, nor the economic viability of a cattle breeding operation. It stated that no evidence is available linking emissions from sour gas processing facilities with problems of cattle health or fertility. In cross-examination of Goldenview Farms, the applicant made reference to a number of purebred cattle breeding operations that are located in close proximity to several sour gas plants in the province. To minimize the visual impact of the plant on Goldenview Farms and its clients, Cdn. Oxy proposed the use of landscape design.

In response to the human health concerns expressed by the CTPC, Cdn. Oxy's position was that since the proposed facility would meet the Alberta ambient air quality regulations for sulphur dioxide and since there is no evidence which indicates that exposure to such levels results in health problems, the proposed facility would not cause human health problems.

With respect to water supply for the gas plant, Cdn. Oxy stated that it is currently negotiating a contract with the Town of High River for the purchase of fresh water supply. It stated that the peak requirements of the plant would be in the order of 115 litres per minute, equivalent to some 10 per cent of current consumption in the town of High River, and that the contract would deliver a fixed daily rate for the life of the contract which should be adequate for the life of the plant. If the Town of High River or the Town of Okotoks were unable to supply the water required, Cdn. Oxy stated that its alternative sources would be the Highwood River or water wells at the plant site. Cdn. Oxy further stated that if it were necessary to choose the latter sources, additional studies would have to be done. In particular, should water wells be required, a detailed study of the groundwater regime would have to be submitted to Alberta Environment to prove that the groundwater system could provide the required volume of water without interfering with other users.

With respect to effects on property values, the applicant acknowledged that the view from the rural residential subdivisions of Alderwood and Highview would be impacted by a plant at either of the proposed sites. However, a study of selling prices for various-sized parcels of land around sour gas plants in southern Alberta, conducted by the applicant, indicated that the presence of gas plants in an area did not negatively affect the value of the properties. It was therefore the applicant's view that construction of the proposed facility in the area would not reduce property values, though locating at site B may have a lesser impact upon the view from the subdivisions of Alderwood and Highview.

### 4.4 Board's Views

On the basis of the evidence put before it, the Board has no reason to believe that the proposed plant would cause cattle health problems. The Board notes that purebred cattle operations exist elsewhere in Alberta near sour gas plants with no particular reports of breeding or cattle health problems. Respecting buyer perceptions of the relationship between industrial activity and cattle breeding, the Board does not believe that such an apprehension of a possible adverse perception is, by itself, sufficient reason to deny the application.

The evidence presented by the applicant indicates that the anticipated ground level concentrations of $SO_2$ would be much below accepted minimum standards and that impingement of sulphur compounds on Goldenview Farms and surrounding lands would be extremely low, in fact less than atmospheric background effects, and would not result in negative impacts. Additionally, no new evidence was presented by the interveners to demonstrate harmful effects on the environment. Therefore, it is the Board's view that, provided the plant operates within the sulphur recovery guidelines, no significant impact on the environment or cattle of Goldenview Farms should result from a plant located at either of the proposed sites.

The Board heard the concerns raised by the CTPC regarding a perception of potential health problems as a result of the operation of the proposed plant but believes that impacts on human health have been fully allowed for in the establishment of the ambient air quality standards. Those standards were established by Environment Canada and are the most stringent specified by that agency. No evidence was presented by the interveners to suggest or demonstrate that the standard is inadequate nor that predicted ground level concentrations would cause human health problems. The Board can only conclude, therefore, that the proposed plant will not have a negative impact on human health.

The Board concludes that the applicant's proposed gas plant water supply source from the Town of High River is satisfactory and that if other sources are required, appropriate studies and applications would be required to ensure acceptability of the alternatives. In particular, the Board notes the intention of the applicant and the requirement which would be placed on the applicant to fully study the hydrogeology of the area prior to any application to Alberta Environment to obtain water from wells.

The Board has no quantifiable evidence before it to indicate that property values would be negatively affected in the vicinity of the proposed plant, nor is it aware of such an effect having occurred in the vicinity of any existing sour gas plant. Notwithstanding the lack of any quantifiable evidence, the Board believes that because the area near site B is less densely populated and site B is some 2.5 kilometres from the edge of the Goldenview Farms property, site B would result in reduced visual impact from Alderwood, Highview, and Goldenview Farms.

With respect to other alternative sites, no other location was suggested as a site which would reduce the impacts arising from the proposed gas plant. Hence, it is the Board's view that site B appears to minimize the environmental impacts of the proposed plant.

# 5 TECHNICAL AND ECONOMIC CONSIDERATIONS ON SULPHUR RECOVERY AND PLANT SITING

## 5.1 Applicant's Views

Cdn. Oxy applied to the Board for approval of a gas processing plant at a sulphur recovery level of 98.0 per cent on a quarterly basis in accordance with ERCB IL 80-24 (IL 80-24)[2]. This quarterly level would ensure a sustained (annual) recovery level of at least 98.3 per cent.

Cdn. Oxy proposed a three-stage Claus process for recovery of 97 per cent of the sulphur contained in the raw gas and a tail gas clean-up unit capable of recovering an additional 2 per cent of the sulphur. It stated that two groups of tail gas clean-up units had been considered. The first group could achieve a normal operating recovery efficiency in the 99 per cent range while the second group could reach the 99.5 to 99.9 per cent range. The applicant stated that it compared the costs of the two groups and the associated emissions of sulphur before concluding that with the equipment required to reach the higher recovery efficiency range, the project would not meet Cdn. Oxy's required rate of return to make the project economically viable. The applicant argued that the proposed facilities would provide the cleanest plant reasonably and economically possible.

With respect to plant siting, the technical and economic criteria that were examined included minimizing the distance from the proposed site to the estimated centre of the reserves, in order to minimize the length and size of gathering system pipeline that would be required, plus other safety and design considerations. Access to transportation services was also considered, including the location of the sales gas pipeline, the length of railway spur that would be required, and the amount of upgrading that would be required to allow road access. The availability of land which could be purchased for a plant site was also considered. From a process of arbitrarily assigning scores to the criteria, in an attempt to rate the relative impact of each criterion, site B was selected as being the preferred site. Site A was suggested as an acceptable alternative site.

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2 Energy Resources Conservation Board, 1980. Sulphur Recovery Guidelines - Gas Processing Operations. ERCB Informational Letter IL 80-24. Calgary, Alberta.

## 5.2 Interveners' Views

The CTPC stated that in principle it did not oppose a gas processing plant being built in the area, but that the proposed sulphur recovery level and the resulting sulphur emission of 14.1 t/d was not satisfactory having regard for the impact the emissions would have on local residents and on the overall air quality of the province.

The CTPC stated that Cdn. Oxy has attempted to do no more than to satisfy the current sulphur recovery guidelines as set out in IL 80-24. The CTPC suggested that at some time in the future the guidelines will be changed to require that plants recover more sulphur than is currently required and that it would be less expensive for Cdn. Oxy to install equipment capable of a higher recovery now rather than later.

Even though the CTPC agreed that building a plant with more complicated tail gas clean up equipment to recover a larger amount of the sulphur might mean a greater frequency of upset conditions, it believed the overall result would be a cleaner plant.

Some members of the CTPC indicated that, having regard for the incremental cost to the project, they do not believe that total sulphur recovery is reasonable. However, these members stated that a compromise between the recovery level required by the Board and zero emissions should be made. Other members argued that a company should not put economics before the health of individuals, hence total recovery should be the target.

## 5.3 Board's Views

The Board agrees with Cdn. Oxy and the interveners that although total sulphur recovery is theoretically possible, varying gas flows and changing plant operating conditions will lead to less than 100 per cent recovery even in the most sophisticated facility. In fact, more complicated design may lead to more difficulties in upset control causing diminished average sulphur recovery efficiency and related environmental problems. The sulphur recovery guidelines set forth in IL 80-24 are designed to ensure the maximum practical recovery of sulphur, but in considering specific cases, allowance must be made for any unique circumstances. The evidence did not indicate any unique circumstances but the Board expects that the design capacity of 99.0 per cent will actually result in a recovery somewhat higher than the 98.3 per cent required by the guidelines. The Board therefore concludes that the proposed sulphur recovery rate is satisfactory. Furthermore, to require a design capacity of 99.9 per cent would result in an estimated average cost of some $2000 per tonne for the incremental sulphur recovered which can be compared to an estimated sales price of about $100 per tonne. Having regard for the extreme unit cost of achieving the last 0.9 per cent recovery, the Board can accept the applicant's contention that requiring the highest possible recovery rate would render the project uneconomic.

With respect to technical and economic criteria as they relate to plant siting, the Board agrees that site B provides the most convenient access to the railway, sales gas line, and roadway. The Board also agrees that site B appears to minimize the length and cost of pipelines that would be required for the gathering system.

## 6 MAINTENANCE OF ADEQUATE SEPARATION DISTANCES BETWEEN SOUR GAS FACILITIES AND RESIDENTIAL AND OTHER DEVELOPMENTS

### 6.1 Applicant's Views

The applicant presented an analysis of the risk that would result from a release of sour gas from a well blowout or pipeline rupture in the gathering system for the proposed plant or from the plant itself. The degree of risk arising from a release from the plant itself was determined to be smaller than from the pipeline due to the smaller potential release volumes involved. The applicant stated that the risks determined by using the separation distances required by ID 81-3[3] were low enough to be considered of insignificant concern to society. The applicant also calculated the degree of risk and predicted the consequences resulting from a pipeline rupture in the vicinity of Goldenview Farms. These calculations, using certain assumptions submitted by Goldenview Farms, indicated that the degree of risk and consequences were very low.

### 6.1.2 Interveners' Views

The position taken by Goldenview Farms at this proceeding, and in another application initiated by itself, was that the risk to the public visiting Goldenview Farms would be acceptable only if Goldenview Farms were afforded the separation distance protection specified for a "public facility" as defined in ID 81-3.

Goldenview Farms requested in final argument that its application to be designated as a public facility be considered concurrently with Cdn. Oxy's application. Goldenview Farms made this request in the event that its public facility application was not found acceptable. Hence, the option would remain open for its application to be considered in this proceeding.

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3 Energy Resources Conservation Board, 1981. Minimum Distance Requirements Separating New Sour Gas Facilities from Residential and Other Developments. Interim Directive ID 81-3. Calgary, Alberta.

### 6.1.3 Board's Views

While the Board does not necessarily agree with all of the assumptions used by the applicant in making calculations of risk and consequences arising from wells and pipelines connected to the proposed facility, it is the Board's view that the separation distances provided for in ID 81-3 provide adequate protection to the public from sour gas facilities. If Goldenview Farms is determined by the Board to be a public facility, then that could affect the separation distances but the impact would relate to the sour gas pipelines only, since the site B location for the plant would meet the separation distance requirement. There is, therefore, no need to consider the Goldenview Farms application in conjunction with that for the plant. The Board sees some merit in considering the Goldenview application in conjunction with that for the plant gathering system but has already agreed to set it down for a hearing on a separate date. At that time Goldenview Farms and any other interested parties will be given an opportunity to express their views.

## 7 EMERGENCY RESPONSE PLANNING

### 7.1 Interveners' Views

The CTPC stated that it wished to be involved in the preparation of emergency response plans for the proposed plant and the wells connected to it. The CTPC also indicated a specific concern regarding the difficulty of evacuating the cul-de-sac in the subdivision of Highview, south of the 6-28-20-28 W4 well, should a sour gas release occur at the north end of the cul-de-sac accompanied by a wind from the north.

### 7.2 Board's Views

The Board is of the view that input from local residents, including the CTPC, should be included in the emergency response plan for the proposed plant and field or fields supplying the plant. The Board intends to ensure that this takes place.

## 8 GENERAL BENEFIT AND COST

### 8.1 Applicant's Views

Cdn. Oxy stated that benefits of its project would be felt at local, provincial, and regional levels primarily in terms of providing rapid depletion of the sour gas reserves in the area prior to future development and urban encroachment. It stated that municipal property

taxes would contribute about $1 million of annual revenue to the Municipal District of Foothills. Over the project life, income taxes and mineral taxes payable to the province would be some $55 million, while taxes payable to the Federal Government would be some $100 million. In addition, royalty payments to the province and to private holders of mineral rights were estimated at $70 million over the project life.

The applicant stated that the project would result in the expenditure in Alberta of some $90 million for construction materials and wages. It estimated annual operating expenditures in Alberta of approximately $4.1 million. Cdn. Oxy contended that regional and local businesses would benefit from the plant not only in terms of supplying certain materials and services but also from indirect income and population growth.

Additionally, the applicant stated that the section of road to the plant site from Highway 2 would be upgraded, thus providing improved access for nearby residents.

### 8.2 Interveners' Views

The interveners did not express views on benefits of the plant other than in terms of rapid depletion of the underlying reserves and resulting benefits of earlier surface development of lands that would be frozen by separation distances specified in ID 81-3. As discussed earlier in this report, the CTPC and Goldenview Farms perceived economic disbenefits in the form of reduced property and cattle values.

### 8.3 Board's Views

The Board agrees generally with the applicant's assessment of the benefits attributed to the proposed plant and associated field activities. The Board has calculated that even if there were no real price increases in marketable gas, liquids, and sulphur over the life of the project, the remaining producible reserves in the Okotoks Crossfield Pool would have a value in excess of $1 billion. The Board concludes that there would be tangible economic benefits to the community and province and that the perceived potential disbenefits such as reduced land and cattle values have not been demonstrated to be likely to occur or to be anywhere near the same magnitude as the potential benefits. In summary, the Board believes the proposed plant would have a strong net benefit to both the area and the province.

## 9 DECISION

Having considered the evidence of the applicant and interveners, the Board believes that the proposed gas processing plant is in the public interest and that its approval would support the general objectives cited in the Board's report to the Lieutenant Governor in Council, Public Inquiry to Consider Potential Conflicts Between Development of Sour Gas Reserves and Residential Development in the Okotoks Area.

The Board has concluded that the most appropriate location for the plant is site B. Also, although pipeline routes were not directly addressed in the application, it appears feasible for the necessary gathering system pipelines to gain access to the plant and still comply with sour gas pipeline setback requirements even if Goldenview Farms were designated as a public facility as defined under ID 81-3.

The Board is therefore prepared to approve the application subject to the receipt of approval of the Minister of the Environment with respect to environmental matters.

DATED at Calgary, Alberta, on 29 July 1983.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

V. E. Bohme
Board Member

N. Strom
Board Member

## APPENDIX A

### THOSE WHO APPEARED AT THE HEARING

| Principals and Representatives (Abbreviations used in Report) | Witnesses |
|---|---|
| Canadian Occidental Petroleum Ltd. (Cdn. Oxy)<br>A. L. McLarty<br>B. DeJonge | R. H. Orthlieb, P.Eng.<br>J. Haufbauer, P.Eng.<br>R. N. Tamasi, P.Eng.<br>G. L. Brown*<br>D. H. Boyd, P.Eng.*<br>Dr. D. M. Leahey*<br>M. B. Schroeder*<br>*of Western Research and Development Ltd.<br>L. H. Larsen, P.Geol. of Pan-Alberta Gas Ltd.<br>J. Lore of McKinnon, Allen & Associates (Western) Ltd. |
| Canterra Energy Ltd. (Canterra)<br>W. J. Major, Q.C.<br>P. H. Major | L. E. Fenwick, P.Eng.<br>D. McCoy<br>E. Plumm, P.Eng. |
| Committee for Toxic Pollutant Controls (CTPC)<br>D. J. Evans | E. Mahaffey<br>J. Rowling<br>A. Nauta<br>L. J. Pipe<br>V. Chant<br>I. Luffman |
| Goldenview Farms Ltd. (Goldenview Farms)<br>S. Carscallen<br>P. D. Edwards | Dr. R. D. Rowe, P.Eng. (Consultant)<br>J. S. McBride<br>R. McDowell<br>H. L. Gunderson (Publisher of a Farming Magazine) |
| Pan-Alberta Gas Ltd. (Pan-Alberta)<br>C. Ayers | |

THOSE WHO APPEARED AT THE HEARING

| Principals and Representatives (Abbreviations used in Report) | Witnesses |
|---|---|
| Rio Frio Ranch Ltd.<br>(Rio Frio Ranch)<br>E. E. McNalley | E. E. McNalley |
| Her Majesty the Queen in Right of Alberta (The Crown)<br>A. R. Watson<br>C. S. Liu, P.Eng. | |
| Energy Resources Conservation Board staff<br>D. A. Holgate<br>E. P. Moeller, C.E.T.<br>W. Roberts | |

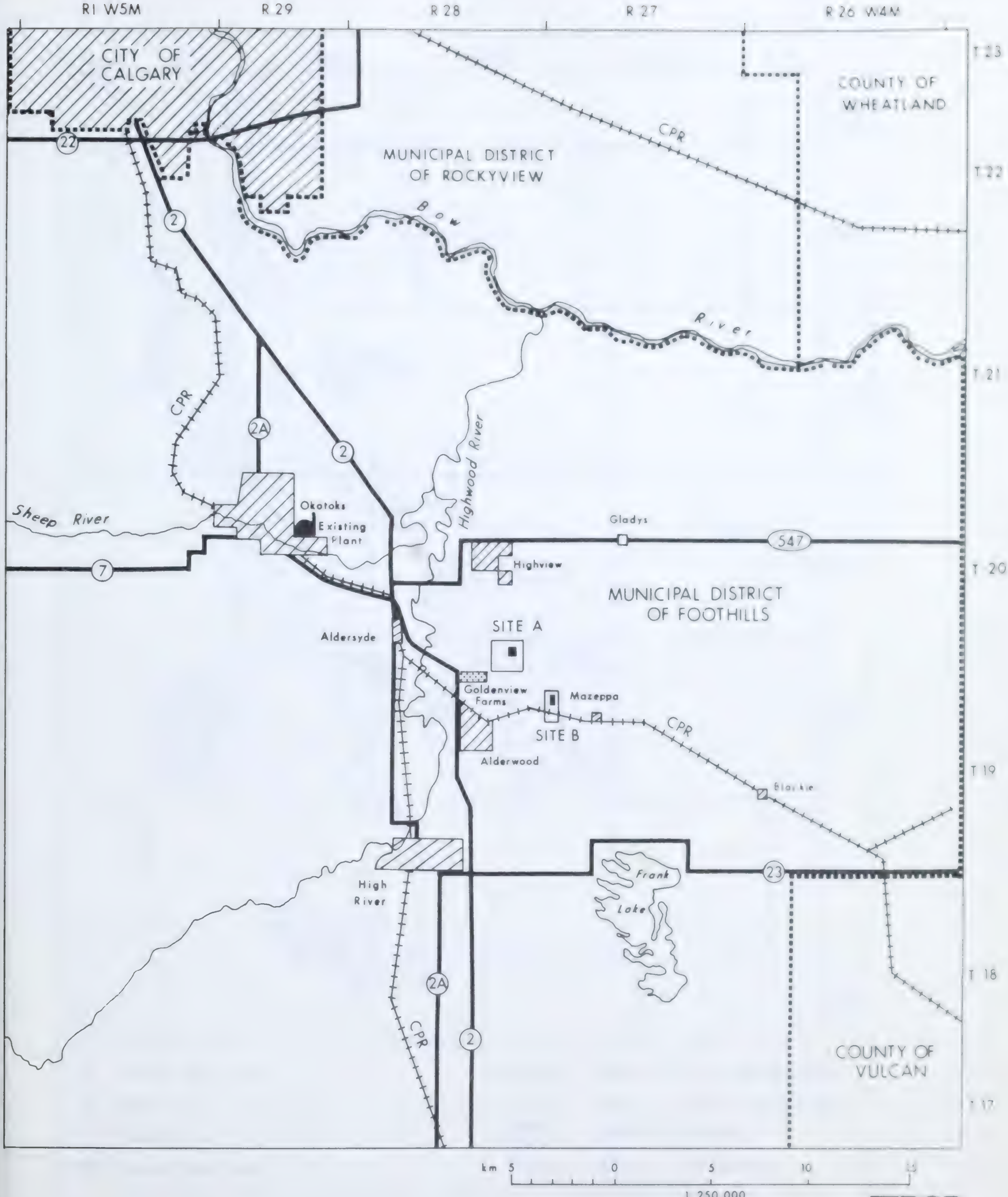



FIGURE 1 CANADIAN OCCIDENTAL PETROLEUM LTD.
APPLICATION NO. 820346
OKOTOKS AREA

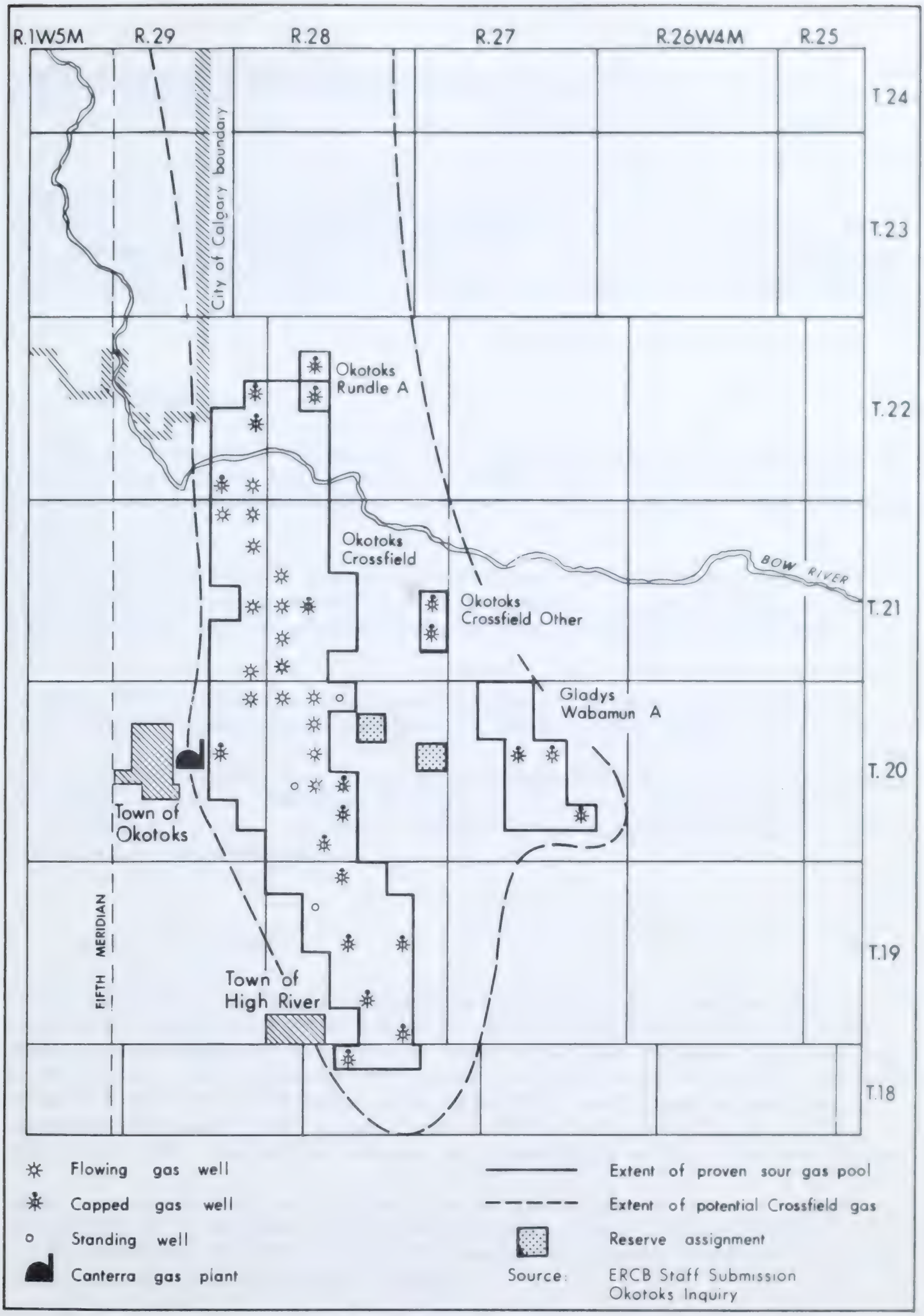



FIGURE 2. THE OKOTOKS AREA. Sour Gas Pools, Wells and Potential Gas Reserves Area

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATIONS BY HUSKY OIL OPERATIONS LTD.
TO REROUTE A SECTION OF APPROVED CONDENSATE AND BITUMEN BLEND PIPELINES BETWEEN LLOYDMINSTER AND COLD LAKE

Decision D 83-14
Applications 830250
and 830251

## 1 INTRODUCTION

In ERCB Decision 81-7 issued in 1981, the Board approved applications by Husky Oil Operations Ltd. (Husky) to construct a crude bitumen blend pipeline and a condensate pipeline between the Lloydminster and Cold Lake areas.

Subsequent unfavourable economic conditions caused Husky to delay the construction of the approved pipelines with the exception of an 11 kilometre (km) section of the lines between the Blackfoot area and Lloydminster.

In 1983, Husky applied to the Board to amend its pipeline permits to incorporate a route change as shown on the attached figure.

The applications were considered at a public hearing in Elk Point on 21 June 1983 with G. J. DeSorcy, P. Eng., N. A. Strom, P.Eng. and L. A. Bellows, P.Eng., sitting. Those who appeared at the hearing are listed in the attached table.

## 2 THE APPLICATIONS

Husky applied to the Board pursuant to Part 4 of the Pipeline Act to amend ERCB permits 19114 and 19115 to alter a portion of the route for combination condensate and bitumen blend pipelines between Cold Lake and Lloydminster. The proposed realignment portion would be shifted westward primarily to link up directly with expanding heavy crude production at Lindberg in township 55, range 6, west of the 4th meridian as well as pass near other production centres as illustrated on the attached figure.

Husky estimated that the capital cost of the proposed reroute would be approximately 5 per cent less than the cost of constructing on the original route and constructing the necessary lateral pipelines to serve Lindberg and other production centres.

Husky's production forecast for the Lindberg area shows production rising from 1400 cubic metres per day ($m^3/d$) in 1983 to 3200 $m^3/d$ in 1993. Husky filed letters indicating qualified support for the proposed reroute from a number of producers. Also, it confirmed that, excluding production from the Esso Leming project, the bulk of the remainder of the heavy oil and bitumen production in the areas intended to be served by its overall system was now being trucked to its Blackfoot truck terminal.

Husky referred to a commitment to Lindberg area producers to target for installation and start-up of that portion of the pipeline system by year-end 1983. The remaining extension to the Cold Lake truck terminal would be scheduled for early 1984 or possibly later.

According to its forecasts, condensate diluent supplies were adequate to meet current production schedules but requirements could grow considerably if production expands as rapidly as forecast.

While shortest access to production centres was a prime factor in reroute selection, Husky had also endeavored to minimize environmental impact by adjusting the reroute to accomodate local features. The new position for the North Saskatchewan River crossing was fully evaluated to ensure geotechnical and environmental integrity. Husky stated that it had negotiated 90 per cent of the necessary easement agreements with landowners on the proposed route and was aware of only one minor route change request that it was negotiating with the landowner.

As part of its application, Husky presented a plan of environmental protection measures which included design details and specified construction procedures. An environmental inspector would ensure that the specifications contained in the environmental plan are adhered to throughout all phases of the construction.

In response to questions by the EPSRA regarding construction on agricultural land during wet weather, Husky stated that the environmental inspector would monitor the situation and that the chief inspector would stop construction activities if it appeared that irreparable damage was being done on the right of way. Husky also stated that it was prepared to accept the conditions attached to its original permits by the Board regarding construction during wet weather.

## 3 THE INTERVENTIONS

### 3.1 Murphy Oil Company Ltd.

Murphy filed evidence showing that its own subsidiary pipeline company, Manito Pipelines Ltd., (Manito) had just recently obtained approval from the National Energy Board (NEB) to construct, during 1984, condensate and heavy oil blend pipelines to serve the Morgan and Hazeldine production

areas. Murphy stated that it was now in the process of developing plans for a further application to the NEB to extend these pipelines to the Lindberg area in about two years. Murphy stated that the proposed Manito pipelines are necessary to ensure a secure feedstock supply for Murphy's proposed processing facilities. Murphy further stated that the heavy oil blend pipeline would have a maximum throughput capacity of 8500 $m^3/d$ and that Husky's proposed reroute to serve producers in the same areas was not required. Although Murphy intervened proposing denial of the Husky reroute, it acknowledged that there was no evidence to show that the public interest would be adversely affected if the reroute were approved.

### 3.2 Elk Point Surface Rights Association

EPSRA stated that it supported Husky's reroute application but was concerned with soil conservation on the right of way and construction during wet weather. EPSRA also expressed concern that uprooting trees to clear rights of way during months when the ground is frozen causes subsoil-topsoil mixing because the subsoil is brought to the surface with tree roots. EPSRA recommended that this type of clearing be done only when the ground is thawed. It further suggested that the topsoil layer on the right of way should be roto-tilled to loosen it so that it could be stripped more easily without mixing with the subsoil.

With respect to construction during wet weather, EPSRA was concerned that irreparable damage could be done to the soil if construction activities continued after the soil became too wet. EPSRA suggested that an independent agrologist be charged with ensuring that pipeline construction crews adhere to required soil conservation practices.

### 3.3 BP Exploration Canada Ltd.

BP questioned Husky regarding tariff structure and the types of arrangements that producers could make with Husky to ship production in the proposed pipeline. BP stated that, as a producer, it had no specific preference for either the proposed Husky pipelines or the existing AEC pipelines to the Cold Lake area, and saw advantages of both pipelines being available.

### 3.4 Alberta Energy Company

AEC appeared at the hearing but did not intervene either in support of or against Husky's proposed reroute.

## 4 VIEWS OF THE BOARD

The applications before the Board are for amendments to accomodate route changes to existing pipeline permits. The Board's assessment of the

applications thus must deal with the merits of the proposed changes in relationship to the project as it is now approved.

The Board considers that the proposed changes should be assessed from the viewpoint of

- o the need for and orderliness of the revised routing,
- o the impact the revised routing could have on the economic viability of the project, the environment, and agricultural operations, and
- o the technical design and operation of the project.

With respect to a need for a routing change, the Board is aware that since the time of issuance of the original pipeline permits, centres of significant heavy crude production in the Lindberg and Hazeldine areas have developed more rapidly than previously expected by Husky. As can be seen from the attached figure, these lie somewhat west of the currently approved pipeline route.

The Board does not see a need for the routing change in the sense that the oil and bitumen from these and other areas along the route could not otherwise be marketed, but it does consider a rerouting to be somewhat more orderly and efficient in that it passes near the main centres of production. The Board believes the advantages of the reroute are reflected in general support expressed by the producers in the area, with the notable exception of Murphy.

The Board notes that Murphy's contention that there is no need for Husky's proposed reroute is based solely on Manito's concept to serve the same areas with another pipeline system. The Board received no evidence to demonstrate that Manito's proposed pipelines would be more efficient or a more orderly means of moving product from the area than Husky's proposed pipelines. Thus the Board does not consider Murphy's intervention to be grounds that would warrant denial of Husky's application for the reroute.

In taking this position the Board recognizes that the Husky proposal is not the only way in which the production from the areas in question could be moved to market. Indeed, the bulk of the production is now being trucked to the Husky Blackfoot truck terminal. The question of a possible need to determine the most efficient way to accomplish the transportation of production is not before the Board at this time.

Insofar as the impact of the proposed route change on the economic viability is concerned, the Board notes that the changes would allow the line to serve the Lindberg and Hazeldine producing areas at a lower capital cost than would be the case with the original routing and the necessary lateral pipelines. The Board thus believes the changes would not detrimentally affect, and indeed could enhance, the economic viability of the project.

In terms of environmental matters, the Board notes that if the length of the laterals necessary to serve the Lindberg and Hazeldine areas were combined with the main pipeline route, the proposed reroute line would be shorter and result in less surface environmental disturbance.

In terms of impact on agriculture, the Board notes that Husky would follow the detailed procedures approved as part of the original application. It specifically undertook to adhere to the existing permit conditions to ensure the least possible adverse impact to soil productivity, and to cease construction operations if the soil became so wet that continued work could damage it.

In regard to the EPSRA proposal of an independent agrologist to maintain surveillance of construction work, the Board continues to believe that the pipeline company (in this case being Husky) through its environmental inspector, has a prime responsibility of diligent adherence to sound soil protection measures. This process as well as surveillance by a representative of the Land Surface and Reclamation Council and an ERCB pipeline inspector should provide ample safeguard against soil damage resulting from failure to observe good soil conservation practices.

The Board notes that the technical design and proposed operation of the pipeline within the route realignment would not differ from that for the remainder of the line. This would be in accordance with relevent pipeline regulations and codes which the Board accepts.

In summary, the Board sees the route changes as proposed by Husky to be logical, orderly and efficient ones, and considers the measures proposed by Husky to be suitable in terms of minimizing impact on the environment or agricultural operations. It thus believes them to be in the public interest and is prepared to approve Husky's permit amendment applications.

The Board does have some concerns that adequate condensate for diluent purposes may not be available over the time period for which it may be needed. The Board believes this matter should be discussed by potential condensate users and the Alberta Petroleum Marketing Commission to ensure appropriate planning arrangements are put in place.

## 5 DECISION

The Board approves application numbers 830250 and 830251 by Husky Oil Operations Ltd. to amend Permit numbers 19114 and 19115 to alter the

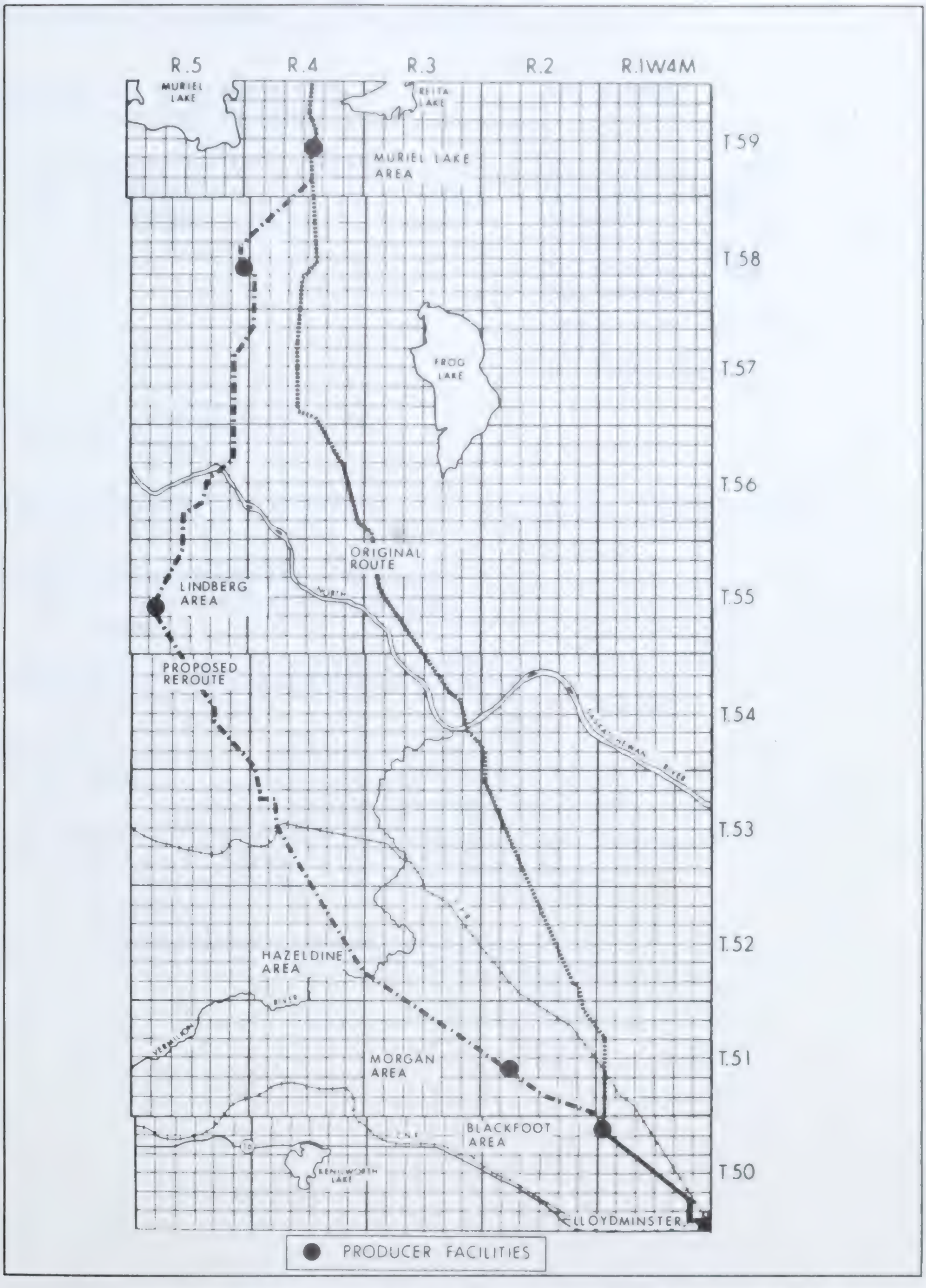
route of a section of the proposed condensate and bitumen blend pipelines as applied-for. It will issue the amended permits upon receipt of the required approval from the Minister of the Environment.

DATED at Calgary, Alberta on 29 June 1983.

G. J. DeSorcy, P.Eng.

N. A. Strom, P.Eng.

L. A. Bellows, P.Eng.




PROPOSED REROUTE OF CONDENSATE AND BITUMEN BLEND PIPELINES BETWEEN BLACKFOOT AND MURIEL LAKE AREAS

ERCB

TABLE THOSE WHO APPEARED AT THE HEARING

| Principals and Representatives (Abbreviations used in Report) | Witnesses |
|---|---|
| Husky Oil Operations Ltd. (Husky)<br>F. R. Foran<br>D. R. Wright | H. J. Berry, P.Eng.<br>T. Graham, P.Eng.<br>V. Smith<br>B. Willis, P.Eng.<br>G. Houston, P.Eng.<br>(of Novacorp. Engineering Services Ltd.)<br>M. Lesky, P.Geol |
| Alberta Energy Company Ltd. (AEC)<br>J. W. Beames, Q.C. | |
| Murphy Oil Company Ltd. (Murphy)<br>L. E. Pasychny | R. D. Urquhart, P.Eng. |
| B.P. Exploration Canada Ltd. (BP)<br>L. G. Hurd (of Foster Research)<br>E. Connolly | |
| Elk Point Surface Rights Association (EPSRA)<br>R. Danyluk | R. Danyluk |
| Alberta Environment<br>R. Dyer | |
| Energy Resources Conservation Board Staff<br>J. D. Dilay, P.Eng.<br>B. C. Hubbard, P.Eng.<br>K. F. Miller<br>S. Sills, P.Eng. | |

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

TRANSALTA UTILITIES CORPORATION 138-kV
AND THE CITY OF CALGARY 240-kV
TRANSMISSION LINE FACILITIES
IN THE NORTH EAST CALGARY AREA

Decision D 83-15
Applications 820874
and 820889

# 1 INTRODUCTION

## 1.1 The Applications

TransAlta Utilities Corporation applied, in Application 820874, for a permit to construct and a licence to operate 138-kV transmission line CP 771L and other related facilities. The line would run several kilometres from the existing Turbo Refinery substation CP 391S to the City of Calgary boundary on the southern edge of the Northwest quarter of Section 36, Township 25, Range 1, West of the 5th meridian (see figure attached), where it would connect with the City line proposed in Application 820889. The application was made pursuant to sections 12, 14, 16, 17 and 18 of the Hydro and Electric Energy Act.

The City of Calgary applied, in Application 820889, pursuant to sections 12, 14 and 17 of the Act, for a permit to construct 240-kV transmission line CC 11.83L and a licence to operate it at 138 kV, and for other related facilities. This line would run north from the City's existing No. 11 substation and connect with TransAlta's line at the City boundary.

## 1.2 The Hearing

The applications were considered by the Energy Resources Conservation Board at a public hearing on 28 June 1983 with C. J. Goodman, P.Eng., V. E. Bohme, P.Eng., and R. G. Evans, P.Eng., sitting.

THOSE WHO APPEARED AT THE HEARING

| Principals and Representatives (Abbreviations Used in Report) | Witnesses |
|---|---|
| TransAlta Utilities Corporation (TransAlta)<br>H. E. Williamson | M. D. Rogers, P.Eng.<br>D. Ansen, P.Eng.<br>R. Nufer, C.E.T. |
| The City of Calgary (The City)<br>R. F. Goss | J. Voss, P.Eng.<br>W. L. McVeigh, P.Eng. |
| Turbo Resources Limited (Turbo)<br>D. Normandin | D. Normandin, P.Eng. |
| Genstar Development Company (Genstar)<br>D. G. Hart | F. Thomas, P.Eng. |
| Bar OW Ranches Ltd. (Bar OW)<br>W. S. Wilson | W. S. Wilson |
| M. Wutzke | M. Wutzke |
| Energy Resources Conservation Board staff<br>C. J. C. Page<br>R. L. Schroeder<br>J. W. Berg, P.Eng. | |

A written submission was filed by Golden West Seeds Ltd. (concerning a portion of the NE 34-25-29W4M) but it did not appear at the hearing.

## 2 THE ISSUES

Having considered the applications and evidence, the Board believes the issues are:

(a) the need for the proposed facilities; and
(b) their location.

## 3 NEED FOR THE PROPOSED FACILITIES

### 3.1 Views of the Applicants

Four aspects of the need for the proposed transmission lines were advanced by TransAlta and the City.

The major reason for the lines is to reinforce the present radial feed 138-kV transmission supply capabilitites in the area of Balzac, Airdrie and Crossfield. Presently, existing facilitites can supply backup to only a small portion of load in this area. With the proposed lines, backup to most of the load could be achieved. TransAlta stated that, with upgrading of

the West Crossfield CP 316S substation in 1984, backup for all the area load could be achieved.

The lines would also provide a second supply to both the Turbo refinery and the Petrogas gas plant, which together make up approximately 25% of the area electrical load. TransAlta said both plants have experienced a substantial number of interruptions which would be greatly reduced, if not eliminated, with the proposed lines. As noted by Turbo, interruptions of three seconds or longer result in the plants shutting down their processes, at considerable cost to the plant owners and with the potential for emergency flaring of gas.

The City of Calgary said that line CC 11.83L would be part of its planned system development, including being the main source to the future City substation, CC 46S, required to serve expanding urban development in the northern section of the City. TransAlta's portion of line, CP 771L, from the Turbo substation would provide a second source to CC 46S. However, the current economic down turn has delayed the requirement for this substation from 1983 until at least 1985. Instead of terminating at CC 46S, initially the proposed line would terminate at CC 11S but would still provide support for a portion of the northern section of the City.

City planning includes diversifying the location of bulk supply substations and, at 138 kV, the line would interconnect with a 138-kV ring around the City. This interconnection would reduce the loading on some of the other sub-transmission facilities within the City. The 138-kV line would adequately serve the area until the mid 1990's when a north-south 500-kV supply would be energized and bulk service to the area is planned to be provided at 240 kV.

## 3.2 Views of the Interveners

Turbo, the only intervener who spoke to the need for the lines, stated that the existing single transmission line CP 752L to the Turbo substation CP 391S has not provided satisfactory service since its installation in 1982. Turbo stated it has experienced an average of one major interruption every six weeks since the line was energized. Turbo considers any interruption longer than three seconds a major interruption.

Turbo also expressed concern with the timing of the project and when the proposed line can be expected to be energized. If its plant were to experience a major interruption of one minute or longer in the coldest part of the winter season, a total freeze-up of the plant is very possible. There is on-site back-up generation of 600 kW available but this represents only approximately 10% of the total plant needs and would not prevent freeze-up. Turbo would like to have an alternative feed in place before the 1983/84 winter season sets in.

## 3.3 Views of the Board

The Board notes that the present system serving the Crossfield-Airdrie-Balzac area is a radial system from one source to the loads. The source is

Crossfield substation CP 64S, which is fed by the 240-kV line CP 901L. Any interruptions to the 240-kV line, or to line CP 752L, result in interruptions to all customers served by the CP 752L radial, and particularly West Crossfield substation CP 316S, Airdrie substation CP 199S, and Turbo substation CP 391S.

The proposed line CP 771L would remove the total dependency of this area on the 240 kV supply at Crossfield substation 64S, and the Board agrees with the applicants that the supply capability to the general area would be greatly improved.

The Board agrees that the additional infeed into the City of Calgary would improve the reliability of service to the northern sections of the City during some contingencies, and should provide support for the long term growth of the northern portion of the City when the electrical supply is at 240 kV.

Having considered these matters, the Board believes the proposed lines are needed.

## 4 THE LOCATION OF TRANSALTA'S PROPOSED TRANSMISSION FACILITIES

Both the TransAlta and City lines would be located within the Calgary Restricted Development Area, therefore consent of the Minister of Environment is required pursuant to Section 5(2) of the Calgary Restricted Development Area Regulations.

### 4.1 Views of TransAlta

In it's original application TransAlta proposed a route identified as A20-A25-A30, shown on the figure. TransAlta later amended its application and requested approval for the route identified as A1-A20-B5-A30-A35, also on the figure. The amended application included a copy of a letter from Alberta Environment stating that Ministerial consent would be granted only if the proposed line followed the Calgary Transportation and Utility Corridor, effectively the route applied for in the amended application.

TransAlta's line would be approximately 6 kilometres (km) long. For the portion of line from the Turbo substation south to the steel towers carrying 240-kV line CP 918L (A35-A30-B5), approximately 1.7 km of new 138-kV wood-pole line would be constructed. An existing 25-kV line would be salvaged and replaced on the new line along this section. The portion of line A30-A35 would be located on right of way which the applicant has acquired from Petrogas. Along segment A30-B1, TransAlta proposes to utilize standard 138/25-kV single-pole structures, 20 metres (m) high, which would be located 1.0 m on the road allowance and should not require any tree clearing.

At the hearing TransAlta further amended its application and modified the design of the line along segment B1 to B5 to use 138/25-kV two-pole lower-profile structures, 10.4 m high. These structures would be approximately the same height as the existing 25-kV line structures, which would be removed, and would avoid any new impact on Mr.Wutzke's airstrip. TransAlta indicated that an 8.4 m right of way, on private property, would

be required along this section of line. The average span between the two-pole structures would be about 76 m compared to 130 m for standard single-pole structures.

Section A1-B5 of the proposed line would be constructed on the vacant side of the steel towers carrying 240-kV line CP 918L. No additional right of way would be required for this section of line.

4.2 Views of the Interveners

Turbo commented on the routing of the proposed transmission line, saying that the concerns of the landowners should be considered so that the line has minimal impact on them.

Mr. Wutzke, the owner of a portion of the NE 34-25-29W4M, objected to TransAlta placing new single-pole structures adjacent to his property on the grounds that the proposed line would interfere with the safe operation of his airstrip that he frequently uses. The airstrip is used only during daylight hours and under VFR conditions and, according to Mr.Wutzke, in conditions of good visibility. He supported TransAlta's proposal to modify the line by replacing an existing 25-kV distribution circuit with new 138/25-kV two-pole structures where the line would be adjacent to his airstrip. Mr. Wutzke stated that the new two-pole line would not interfere with the use of his airstrip as long as the structures were no higher than the present 25-kV line structures.

In response to a question about a second airstrip on property north of his, Mr. Wutzke said he thought that airstrip had not been used for about a year and that the owner was not living there at present.

4.3 Views of the Board

The Board notes that Mr. Wutzke is the only landowner adjacent to the A30-B5 segment of the proposed line who appeared at the hearing; and thus the Board must rely on the evidence of Mr. Wutzke and TransAlta with respect to the airstrips, any clearing of trees, or related matters.

The Board acknowledges that the proposed line could interfere with the safe operation of the private airstrip that Mr. Wutzke frequently uses, and a second private airstrip that may or may not be in use. The Board notes TransAlta's proposal to modify the design of the line along segment B1-B5, by using lower profile structures, to insure that the new line is no higher than the existing 25-kV distribution line, and to place structures in locations to avoid interference with Mr. Wutzke's runway. The Board notes that this arrangement would satisfy Mr. Wutzke's concerns with regard to safe operation of his airstrip. Neither airstrip appears to have an official status and there was no evidence that the second airstrip was in use or that its owner was concerned about any impact of the proposed line. Accordingly, the Board would not expect TransAlta to extend any modification proposed beyond the Wutzke airstrip. However, the Board does believe it would be prudent for TransAlta to place proper aircraft warning markers on the proposed line if it is built in the flight path to either airstrip.

The Board notes that along alignment B1-B5 the applicant would require 8.4 m of right of way on private property. It believes, however, that the impact on landowners immediately adjacent to the line would be acceptable since, according to TransAlta, no tree clearing would be required and there are no residences south of point B1 and east of this segment of the proposed line.

The Board notes that the portion of line A30-B1 would be completely on road allowance, and that an existing 25-kV distribution line would be transferred to the new line. Route A30-A35 is on property acquired from Petrogas, and line segment A1-A20-B5 would be strung on the open side of an existing steel tower line. The proposed route along these segments of line does not appear to cause any major impacts.

The Board finds route A1-A20-B5-B1-A30-A35 to be suitable for transmission line CP 771L.

## 5 THE LOCATION OF THE CITY'S PROPOSED TRANSMISSION FACILITIES

### 5.1 Views of the City

The City submitted only one route for it's portion (CC 11.83L) of the proposed line, identified as C1-A1 in the figure. The line is approximately 5.5 km long and would be located on a 30.5 m right of way presently owned by the City. From No. 11 substation the proposed transmission line would run north along Nose Creek Valley, east of the Canadian Pacific Railway (CPR) right of way, to interconnect with TransAlta's proposed 138-kV line CP 771L. The City indicated that the general routing of the line maintains a reasonably straight alignment that would require few of the more massive and expensive angle towers.

The City indicated that along portions of the proposed route it will be necessary to shield some existing CPR communication systems due to interference from the transmission line. The longer the line parallels the CPR facilities the more mitigation will be required. The applicant indicated that it is still negotiating with CPR with respect to necessary mitigation.

The proposed line would be built as a 240-kV double circuit steel tower line, however, initially only one circuit would be strung and energized at 138 kV. The average span for this steel tower line is 350 m.

In response to the suggestion by Genstar and Bar OW that the line be placed adjacent to the CPR right of way, the City indicated that such a proposal would cause additional interference with the CPR communications facilities and would result in a number of costly deflections in the line. The cost of this alignment was estimated by the City to be approximately \$150 000 - 200 000 more than the applied-for route, which includes the cost of angle towers and possible additional shielding of CPR communications systems. The City, however, had not had discussions with the CPR to determine what additional shielding would be required if the line were to be placed as suggested by the interveners. In any event, the most it could

move the line from the proposed location would be about 30 m to the west because of existing encumbrances adjacent to and east of the CPR right of way, which include the Beddington railway siding located in the NW of 23-25-1W5M and a water injection pipeline right of way in the NW 23- and SW 26-25-1W5M.

The City stated that studies done in May 1980 indicated the possibility of industrial development on the land owned by Genstar and Bar OW. However, the most recent development proposal (the Stony Industrial Area Structure Plan December 1982) indicates that the subject lands are now classified as Open Space, with a high possibility of being developed as a golf course.

5.2 Views of the Interveners

Genstar, the owner of the NW 23-25-1W5M, objected to the location of the proposed transmission line right of way through its parcel of land. In 1978, when the City purchased a right of way for the subject line, Genstar had not evaluated the potential uses of its land. Genstar indicated that a number of Area Structure Plans have been released for this area in the last few years and, with this information, Genstar now believes that there are two potential uses for its property; one being light industrial, and the other, open space, which might include a golf course.

Genstar stated that placing the proposed transmission line on the existing right of way would bisect and therefore interfere with the future development of its property by sterilizing approximately a 75 m strip of land between the railway and the transmission line. Genstar suggested that the line be located to the west, immediately adjacent to the east side of the railway. Genstar noted that the City proposed to parallel the railway for those portions of line traversing sections 11 and 14. It stated that the City had not investigated the amount of additional shielding that would be required if the line were placed parallel to the CPR on Genstar property. Genstar indicated it would be willing to give the City the necessary lands adjacent to the railway in exchange for the present right of way.

Mr. Wilson, representing Bar OW, the owner of the SE 26-25-1W5M, objected to the location of the proposed line on Bar OW property which is presently being used as a cattle pasture. Mr. Wilson stated that the right of way for the proposed line was expropriated by the City in 1982, and that a report by an inquiry officer into the expropriation indicated that the City consider moving the power line right of way closer to the easterly boundary of the railway right of way. In Mr. Wilson's opinion the proposed transmission line would cause fragmentation of the property and would therefore interfere with the potential for future development. He suggested the City build the line adjacent to the CPR railway to avoid dividing the land.

## 5.3 Views of the Board

It appears to the Board that the City already has an existing right of way for its proposed line. This right of way was procured, in part, through a legally constituted expropriation process and on part through negotiations with the owners. The City located this right of way in a more or less straight line from its substation CC 11S to the interconnection with TransAlta's line at point A1, thereby avoiding a substantial cost for deflection towers and possible mitigation of interference with railway communication circuits. An impact of the location is the creation of a strip of land up to 75 m wide between the proposed line and the existing CPR property. The Board accepts that moving the line closer to the railway would of course reduce any separation of lands, but notes that the railway siding and other encumbrances would not allow a contiguous paralleling of the CPR property, even if any communication interference problem were overcome.

The Board notes the City's contention that the December 1982 Area Structure Plan classifies the subject lands as Open Space, and that development of a golf couse is likely. Should this take place, the proposed line would have some impact but would not preclude such development. The Board believes the impact would be more severe for industrial development, but not insurmountable. If, in spite of the current Open Space classification, industrial development were to take place, careful planning would be necessary to make best use of the land around the transmission towers and to ensure that adequate clearance was maintained from the conductors. However, there was no evidence advanced that an industrial development plan had been prepared and approved for the area, or that industrial development would be precluded by the location of this line, and the Board does not find a compelling argument for changing the route of the City's proposed line, regardless of the existence of any City right of way.

In summary, the proposed line would follow the least costly and most direct route and would not cause major impacts to the likely future use of Genstar and Bar OW lands. On this basis the Board agrees with the City that the route from No. 11 substation to the interconnection with TransAlta's line is suitable. However, the eventual land use has not yet been fixed and the City should, to the extent possible, ensure that the location of its towers within its right of way, the span lengths, and the conductor height above ground, recognize the possible future uses of the land traversed. In particular, conductor height should be adequate for future access by vehicles to the land between the line and the railway.

# 6 FINDINGS

The Board, having publicly heard the evidence submitted by TransAlta Utilities Corporation, The City of Calgary, and the interveners, finds that:

1. There is a need for the proposed transmission line;
2. TransAlta's proposed route from A1-A20-B5-A30-A35 is suitable; and
3. The proposed City of Calgary route from No. 11 substation north to point A1 is suitable.

## 7 DECISION

The Board approves the TransAlta Utilities Corporation Application 820874 as amended; and the City of Calgary Application 820889. The overall transmission line Route C1-A1-A20-B5-A30-A35 is shown in the figure. Subject to the approval of the Minister of Environment and the Minister of Energy and Natural Resources insofar as the applications affect matters of the environment, and subject to the consent of the Minister of Environment pursuant to Section 5(2) of the Calgary Restricted Development Area Regulations, the Board will issue the permits and licences in due course.

ISSUED at Calgary, Alberta, on 18 August 1983.

ENERGY RESOURCES CONSERVATION BOARD

C. J. Goodman

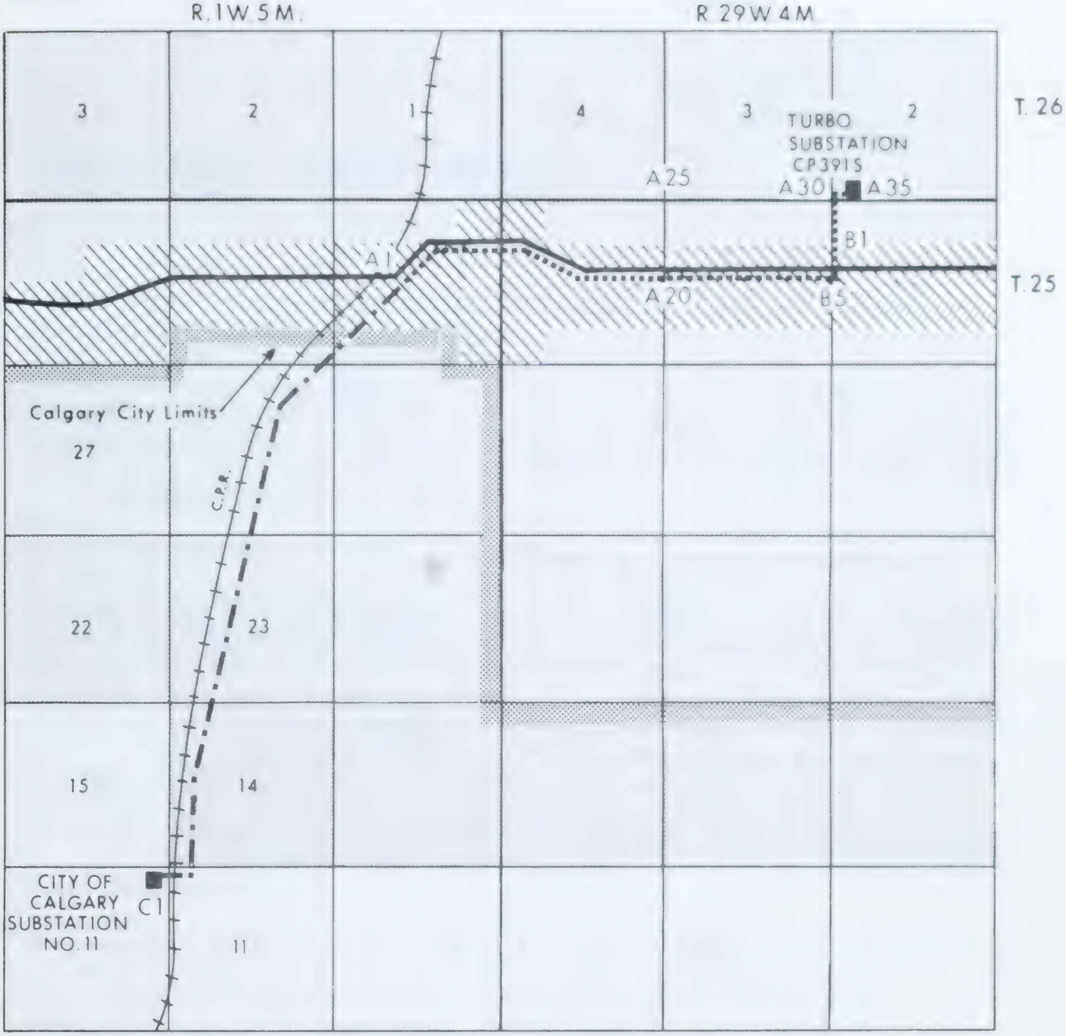
C. J. Goodman, P.Eng.
Board Member

V. E. Bohme

V. E. Bohme, P.Eng.
Board Member

R. G. Evans

R. G. Evans, P.Eng.
Acting Board Member




LEGEND

City of Calgary 240 kV Transmission Line CC11.83L (To be operated at 138 kV)

TransAlta Utilities Corporation 138 kV Single Circuit Transmission Line CP771L

Existing 240 kV Transmission Line

Transportation and Utility Corridor

Restricted Development Area

TRANSALTA UTILITIES CORPORATION / THE CITY OF CALGARY

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATIONS BY ALBERTA ENERGY COMPANY LTD.
TO CONSTRUCT CONDENSATE AND BITUMEN
BLEND PIPELINES AND PUMPING FACILITIES
IN THE FORT KENT AREA AND
TO CONSTRUCT PUMPING FACILITIES
IN THE BELLIS AREA

Decision D 83-16
Applications 830215, 830216,
830217, 830218 and 830219

## 1 INTRODUCTION

Alberta Energy Company Ltd. (AEC) applied to the Energy Resources Conservation Board (Board) pursuant to the Pipeline Act, for permits to construct two 26 kilometre (km) parallel pipelines in the Fort Kent area. A 114.3 millimetre (mm) pipeline would transport condensate from AEC's existing condensate pipeline in legal subdivision 12 of section 30, township 63, range 5, west of the fourth meridian to a proposed pump station in Lsd 13-21-61-4 W4 for blending with crude bitumen. A 219.1 mm pipeline would transport blended crude bitumen from the proposed pump station in Lsd 13-21-61-4 W4 to AEC's existing crude bitumen blend pipeline in Lsd 12-30-63-5 W4. Additionally, AEC applied for approval to construct two pump stations in Lsd 8-15-59-16 W4 (Bellis area), one on its existing condensate pipeline and one on its existing crude bitumen blend pipeline.

The applications were considered at a public hearing in Elk Point on 21 June 1983 with G. J. DeSorcy, P.Eng., N. Strom, P.Eng. and L. A. Bellows, P.Eng. sitting. Participants at the hearing are identified in the attached table.

## 2 THE APPLICATIONS

AEC stated that the proposed pipelines and pumping facilities were necessary because Suncor Inc. Resources Group (Suncor) wanted to utilize AEC's Cold Lake to Edmonton pipeline to ship crude bitumen production from its Fort Kent thermal project. The bitumen production rate from expanded Fort Kent facilities is expected to be 795 cubic metres per day ($m^3/d$) by the fall of 1984 when the pipeline is expected to become operational. AEC stated that it had negotiated a letter of intent with Suncor for the utilization of 795 $m^3/d$ capacity in its pipeline and that tariff negotiations were proceeding.

AEC further explained that its tariff structure for use of its main pipeline between Cold Lake and Edmonton is such that a doubling of throughput in the pipeline would result in a halving of the per unit tariff. It is therefore economically beneficial to all producers using the line for it to be utilized to the fullest extent possible. AEC submitted a letter of support for the proposed Fort Kent lateral pipeline from Esso Resources Canada (Esso) which is presently the sole user of the Cold Lake to Edmonton pipeline.

The present capacity of the AEC mainline is approximately 2860 $m^3/d$ bitumen (or "dry crude") and is fully utilized by production from Esso's Leming project. Sufficient capacity can be added to the line to accommodate Suncor's expected production by the installation of pumping facilities on both the crude bitumen blend pipeline and the condensate pipeline in the Bellis area. AEC stated that the capacity of its Cold Lake to Edmonton crude bitumen blend pipeline could be increased to a maximum of 7800 $m^3/d$ bitumen by the installation of additional pumping capacity.

In summary, AEC stated that connecting Suncor's Fort Kent facilities to the AEC Cold Lake to Edmonton pipelines would be an economic, orderly and efficient use of the existing pipelines.

In regard to the applied-for route, AEC stated that it had evaluated four possible routes for the proposed pipelines before selecting the one it preferred. Each route was evaluated having consideration for the best location to connect with the existing condensate and bitumen blend pipelines, minimizing impact on the Beaver River and Jackfish Creek, minimizing disturbance to other land uses, and paralleling existing linear disturbances wherever possible. AEC concluded from the evaluation of the four routes, that the one which has been applied for is the most acceptable from an environmental impact point of view. The preferred route was then further refined and adjusted to accommodate landowner requests on a site-specific basis.

AEC stated that it had submitted a Development and Reclamation plan in support of its applications for the proposed pipelines to the ERCB. The plan, which contains detailed environmental protection measures to be employed during construction of the proposed pipelines, would be included as part of the construction contract if approved by Alberta Environment.

AEC stated that 364 $m^3/d$ of condensate would be required for blending with Suncor's anticipated crude bitumen production of 795 $m^3/d$. AEC further stated that its 10 year production forecast for the general Cold Lake area north of the North Saskatchewan River showed production rising to 17000 $m^3/d$ which would require approximately 5000 $m^3/d$ of condensate diluent for transportation to export markets.

## 3 VIEWS OF THE BOARD

The Board is satisfied that there is adequate justification for the proposed pipelines and pump station in the Fort Kent area in terms of the general benefits of connecting Suncor's production to AEC's existing pipelines. This is emphasized by the support for the applications from Esso, the principal user of the existing system, Suncor, which would be served by the proposed lateral, and other area producers. The Board is also satisfied that the proposed Bellis area pump stations on the AEC pipelines are necessary to accommodate the additional crude bitumen blend and condensate throughputs.

With respect to the proposed route for the Fort Kent lateral, the Board believes the preferred route to be acceptable from an environmental impact basis, and to be superior to the investigated alternatives. The major reasons for this are the fewer number of and less difficult stream crossings, and avoidance of wildlife areas and wetlands.

The Board believes that the construction procedures proposed by AEC would minimize impacts on the environment and on agricultural lands. In this respect, it notes that no landowners, or indeed others, intervened into the application or appeared at the hearing to raise such possible concerns.

The technical design and proposed operations are in accordance with the relevent pipeline codes and regulations.

The Board notes that AEC's evidence indicated that about 5000 $m^3/d$ of condensate would be required as diluent for its forecasted 17000 $m^3/d$ of bitumen production. The Board estimates, however, that if the presently used 70/30 blend ratio is maintained, the condensate requirement would in fact exceed 7000 $m^3/d$. The Board does have some concerns that adequate condensate for diluent purposes may not be available over the time period for which it may be needed and believes this matter should be discussed by potential condensate users and the Alberta Petroleum Marketing Commission to ensure appropriate planning arrangments are put in place.

## 5 DECISION

The Board approves application numbers 830215, 830216, 830217, 830218, and 830219 by Alberta Energy Company Ltd. for pipelines and pumping facilities as applied for. Permits will be issued upon receipt of the necessary approvals from the Minister of the Environment.

DATED at Calgary, Alberta on 8 July 1983.

G.J. DeSorcy

G. J. DeSorcy, P.Eng.

N. Strom

N. Strom, P.Eng.

L.A. Bellows

L.A. Bellows, P.Eng.

THOSE WHO APPEARED AT THE HEARING TABLE

| Principal and Representatives (Abbreviations used in Report) | Witnesses |
| --- | --- |
| Alberta Energy Company Ltd. (AEC)<br>J. W. Beames, Q.C. | J. E. Ellefson, P.Eng.<br>J. Russel, P.Eng.<br>M. Benson<br>C. Edey |
| Husky Oil Operations Ltd. (Husky)<br>F. R. Foran | |
| Murphy Oil Company Ltd. (Murphy)<br>R. D. Urquhart, P.Eng. | |
| B.P. Exploration Canada Ltd. (BP)<br>L. G. Hurd (of Foster Research) | |
| Alberta Environment<br>R. Dyer | |
| Energy Resources Conservation Board staff<br>K. F. Miller<br>J. D. Dilay, P.Eng.<br>B. C. Hubbard, P.Eng.<br>S. Sills, P.Eng. | |

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

Decision D 83-17

ICG RESOURCES LTD. — Applications 830165, 830166 and 830167
LICENCE TO DRILL A WELL AND PERMITS TO CONSTRUCT TWO PIPELINES IN THE CROSSFIELD-AIRDRIE AREA



CANADIAN OCCIDENTAL PETROLEUM LTD. — Applications 830460 and 830461
SPECIAL DRILLING SPACING UNIT APPLICATION AND LICENCE TO DRILL A WELL IN THE CROSSFIELD-AIRDRIE AREA

PETROGAS PROCESSING LTD. — Applications 830488 and 830489
PERMITS TO CONSTRUCT TWO PIPELINES IN THE CROSSFIELD-AIRDRIE AREA

# 1 INTRODUCTION

ICG Resources Ltd. (ICG), Canadian Occidental Petroleum Ltd. (CanOxy), and Petrogas Processing Ltd. (Petrogas), each filed applications pursuant to the Oil and Gas Conservation Regulations and the Pipeline Act which in total were for a special drilling spacing unit, licences for two wells, and permits for the associated pipelines in the Crossfield-Airdrie area.

The area of application for the special drilling spacing unit, the location of the proposed wells, and proposed pipeline routes are shown on the attached figure.

Since the applications came forward at approximately the same time and the proposed wells would be in close proximity to each other, the Board considered the applications at one hearing and is reporting on them all in this report.

A public hearing of the applications was held on 12 July 1983, in Calgary, Alberta, with G. J. DeSorcy, P.Eng., N. Strom, P.Eng., and L. A. Bellows, P.Eng., sitting. Those who appeared at the hearing are listed in the attached table.

# 2 THE APPLICATIONS

## 2.1 Applications of ICG

Under Application 830167, the applicant proposes to drill a well in legal subdivision 13 of section 23, township 27, range 29, west of the 4th meridian (the 13-23 well), to evaluate and obtain production from all the formations down to and including the Crossfield Member of the Wabamun Group. It is anticipated that production of sour natural gas,

with an estimated maximum hydrogen sulphide ($H_2S$) content of 350 mol/kmol (35 per cent by volume), would be obtained from the Crossfield Formation.

Application 830165 is to construct approximately 1.60 kilometres (km) of 60.3-millimetre (mm) outside diameter (O.D.) sweet fuel gas pipeline from an existing CanOxy fuel gas pipeline in legal subdivision 13 of section 26, township 27, range 29, west of the 4th meridian to the proposed 13-23 well.

Application 830166 is to construct approximately 1.66 km of 88.9-mm O.D. sour gas pipeline to tie-in the proposed 13-23 well to the existing CanOxy gas gathering system in 13-26.

ICG stated that it has obtained the mineral rights for section 23 and that the proposed well is necessary to produce the reserves it believes underlie the section. ICG also said that the well would prevent drainage toward existing producing wells to the north.

Regarding the need for its proposed pipelines, ICG stated that they are needed to transport gas from its proposed well to market and to supply fuel gas for well-site facilities. The attached figure shows that the proposed ICG pipelines parallel a pipeline proposed by Petrogas. In this regard, ICG stated that if the proposed CanOxy well and the 13-23 well were both subsequently demonstrated to be commercial producers, it has been agreed that ICG would use the Petrogas pipeline instead of constructing its own. However, the applicant noted that it would require its proposed pipelines should only the 13-23 well be successful.

ICG indicated that while it had no sales contract for its gas at this time, it had made arrangements with Petrogas for the processing and sale of the gas.

ICG stated that its proposed gas gathering pipeline would be a Level 1 facility as classified by ERCB Interim Directive ID 81-3[1]. It estimated the $H_2S$ content of the gas to be transported to be about 350 mol/kmol but agreed to maintain the Level 1 $H_2S$ release volume if the actual $H_2S$ content is found to be higher after completing the 13-23 well. It stated that the tie-in location to the existing CanOxy line had been selected to minimize the length of the pipeline and thus the potential $H_2S$ release volume.

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1 Energy Resources Conservation Board, 1981. Minimum Distance Requirements Separating New Sour Gas Facilities from Residential and Other Developments. ERCB Interim Directive ID 81-3, Calgary, Alberta. ID 81-3 classifies sour gas facilities by the potential $H_2S$ release volumes or rates.

## 2.2 Applications of CanOxy

Under Application 830461, the applicant applied pursuant to section 4.050 of the Oil and Gas Conservation Regulations, for an order to establish the fractional section 22, township 27, range 29, west of the 4th meridian (fractional section 22), as a special drilling spacing unit for the production of gas. CanOxy stated there is no target area currently established for the fractional section 22. The applicant proposed that the target area for the fractional section 22, which consists of approximately 127 hectares, be in accordance with section 4.020(3) of the Oil and Gas Conservation Regulations, as if the fractional section were a normal one section gas well drilling spacing unit. According to CanOxy, the proposed target area would be within the central part of the partial section, having sides 290 metres from the sides of the partial section and parallel to them.

Under Application 830460, the applicant proposes to drill a well in legal subdivision 10 of section 22, township 27, range 29, west of the 4th meridian (the 10-22 well), to evaluate and obtain production from all formations down to and including the Crossfield Member of the Wabamun Group. It is anticipated that production of sour natural gas, with an estimated maximum $H_2S$ content of 420 mol/kmol would be obtained from the Crossfield Formation.

CanOxy said that the reason for both the special drilling spacing unit application and the application for a well licence was to allow it to drill a well to recover gas under land it had leased and to prevent drainage of reserves towards the north.

## 2.3 Applications of Petrogas

Application 830488 is to construct approximately 0.04 km of 88.9-mm O.D. and 3.32 km of 114.3-mm O.D. sour gas pipeline from the proposed 10-22 and 13-23 wells to the existing CanOxy gas gathering system in 13-26.

Application 830489 is to construct approximately 3.3 km of 60.3 mm-O.D. sweet fuel gas pipeline to the 10-22 and 13-23 well sites.

Petrogas stated that its proposed lines would be needed to tie-in the subject wells if successful, and that there is a gas sales contract for the proposed 10-22 well. Petrogas also confirmed that it had agreed with ICG to tie the proposed 13-23 well into its pipeline and to process and sell the gas from the ICG well. Petrogas also said it would probably amend the pipeline size and the proposed route from the 10-22 well to the existing gas gathering system if the 13-23 well was not successful.

Regarding an objection from Mr. and Mrs. Allen T. Fletcher with respect to the level of the proposed Petrogas sour gas pipeline, as determined in accordance with Interim Directive ID 81-3[1], the applicant stated the subject pipeline would be a Level 2 facility whether 350 mol/kmol $H_2S$ or 420 mol/kmol $H_2S$ is used for the calculation of the potential $H_2S$ release.

Petrogas said that 3 additional sectionalizing emergency shut-down valves would be needed to limit the potential $H_2S$ release to reach a Level 1 category. It suggested that the installation of additional valves was not justified because the required surface facilities (leases, roads, and above-ground piping) would impact the existing farming operations, would increase the risk of third-party damage to the proposed facilities, and would increase the cost of the pipeline. Petrogas argued further that its pipeline would not significantly impact the Fletcher's property because they have no immediate subdivision plans and the high quality of their farmland would probably preclude subdivision.

## 3 THE INTERVENTIONS

### 3.1 The Fletchers

The Fletchers, owners of the W 1/2-23-27-29 W4M, objected to the proposed Level 2 Petrogas sour gas pipeline because this facility would restrict future subdivision of their property. However, they stated they would not object to the pipeline if it was constructed to be a Level 1 facility, which would have less subdivision land restrictions associated with it.

### 3.2 Associated Engineering Services Ltd.

Associated Engineering Services Ltd. (AESL), representing a group of landowners in section 15-27-29 W4M, stated it had no specific concerns regarding any of the proposed facilities as applied for. AESL said it would be concerned if it was determined the proposed facilities should be located further south because the facilities might then have a negative impact on possible annexation and future development plans of its clients.

### 3.3 Austin Exploration Ltd.

Austin Exploration Ltd. (Austin), on behalf of itself and Normac Oils Ltd., filed a submission in support of ICG's application for a well licence for the proposed 13-23 well. Austin's submission outlined the existing contractual obligations of the companies and it fully endorsed the drilling of the 13-23 well which Austin stated is required to honor the obligations.

## 4 THE ISSUES

Respecting the subject applications, the Board believes the following matters should be considered:

(a) the request for the special drilling spacing unit,
(b) the nature of the reservoir and the need for the proposed wells,
(c) safety considerations and special controls if the wells are drilled,

(d) need for and routes of proposed pipelines,
(e) the $H_2S$ release volume of the applied-for Petrogas pipeline.

## 5 THE REQUESTED SPECIAL DRILLING SPACING UNIT

CanOxy applied for a special drilling spacing unit for fractional section 22, with the proposed target area being as if the fractional section were a normal one section gas well drilling spacing unit.

As there were no objections to this special drilling spacing unit application from off-set mineral owners and there exist no other reasons for denial, the Board is prepared to approve the application to provide for equity and efficient drainage of the postulated reserves underlying fractional section 22.

## 6 NATURE OF THE RESERVOIR AND NEED FOR THE WELLS

The Crossfield East Wabamun A Pool is a sour gas pool of the Crossfield Member. There are ten ERCB designated pools in this geological member that extends from Olds to High River. They are separated by areas that are presently undrilled so it is unknown if there are gas reserves in place in these unexplored areas.

The Crossfield Member consists of a dolomitized fossiliferous back deposit located on the edge of an evaporitic basin. Although there are some high permeability areas in the subject pool, the flow capacity diminishes significantly toward the edges of the pool, especially to the east due to anhydrite infilling of the porosity.

The applied-for wells are to the south and east of the known boundaries of the pool and therefore are exploratory in nature. Though the Crossfield Member is known to exist in this area, it is unknown whether an economic well can be drilled at either of the applied-for locations. The Board believes that the proposed wells, whether successful producers or not, would help delineate the Crossfield East Wabamun A Pool and thus enhance the efficient depletion of the pool's reserves.

The gas in this pool has an average $H_2S$ content of approximately 350 mol/kmol with the possibility of individual wells having an $H_2S$ content of up to 420 mol/kmol. Due to the proximity of these pools to highly populated areas, it is generally agreed that expeditious depletion of these pools is in the public interest. Two additional withdrawal points may either shorten the pool's life or allow recovery of more reserves in a set producing life.

The addition of the subject wells may also serve equity in that pressures recorded in nearby wells indicate that, if the expected gas reserves do exist, the area is being drained to some extent from adjacent existing wells currently producing from the pool.

Having regard for the reservoir characteristics, the exploratory nature of the wells, the $H_2S$ content of the gas, and equity considerations, the Board concludes that there is a need for the proposed wells.

## 7 SAFETY CONSIDERATIONS AND SPECIAL CONTROLS IF THE WELLS ARE DRILLED

### 7.1 Views of ICG

With respect to safety, ICG indicated that it contacted approximately 75 per cent of the residents within 3 km of its proposed 13-23 well. Only four parties expressed apprehension relating to the dangers of a blowout during drilling operations. ICG stated it would make every effort to ensure that safe drilling practices were followed and to minimize the possiblity of a release of sour gas. It stated that $H_2S$ detectors, pit level indicators, and return drilling mud flow detectors would be used in addition to "Class 4 BOP"[2] equipment. ICG also indicated that an $H_2S$ scavenger drilling mud additive would be used while drilling into the Crossfield Member.

The applicant advised that the probability of a blowout during drilling would be remote because of low formation permeability.

ICG stated that in order to further protect area residents from sour gas, it has prepared an emergency procedures plan, which was filed with the well licence application, and its plan will be revised as necessary to obtain ERCB approval. Specially trained safety personnel and equipment would be on location to assist in the detection of $H_2S$ and to protect the drilling crews if a problem occurred. ICG outlined that the drilling rig would be manned and supervised by well-trained and knowledgeable drilling personnel including sufficient staff to provide back-up personnel in case of an accident or injury. The rig would utilize a drilling mud degasser and a flaring system to incinerate all controlled releases of $H_2S$ at the well site.

ICG stated that its submitted emergency procedures plan would be in operation until production casing was set and during the completion of the well. It further stated that there should be no uncontrolled release of $H_2S$ during the completion stage as the tubing, packer, and wellhead would be installed prior to the proposed well being perforated.

ICG indicated that following a successful completion, a plug would would be set in the tubing string and the tubing filled with an inhibited fluid. During this standing phase, the wellhead valves would be secured with chains and locks.

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2 Blowout prevention (BOP) equipment requirements are detailed in the Oil and Gas Conservation Regulations.

ICG indicated that its proposed production operations would be carried out under the direct supervision of CanOxy and Petrogas. Any emergency that may occur would be handled under Petrogas's existing emergency procedures plan which has been formulated for its Balzac gas plant and the associated field facilities.

To protect against the very remote chance of an $H_2S$ release during production, ICG stated the proposed 13-23 well would be equipped with a subsurface safety valve, an emergency shut-down valve on the wellhead, and an emergency shut-down valve at the line heater. The applicant indicated that all safety valves would be of a "fail-close"[3] design that would close the well when pressures fluctuate above or below a pre-set level.

Additionally, ICG said that its hot-oil circulating unit would be equipped with safety valves that would close if communication with the tubing string ever occurred. The applicant indicated that an existing cable telemetry system would be extended to the proposed 13-23 well and installed, which would then enable operators at the Petrogas Balzac gas plant to remotely shut the well in at the line heater from the gas plant control room, if problems arose.

ICG affirmed that all its proposed surface wellhead equipment would be adequately fenced and that it would install $H_2S$ warning signs at these facilities in the interest of safety and security.

7.2 Views of CanOxy

Regarding safety, CanOxy stated that the possibility of an emergency situation arising during the drilling of the well is very remote due to the low permeability that is expected to be encountered in the Crossfield Member. The applicant stated it was most familiar with the area and, based on the adjacent wells that have been drilled, confident that reservoir pressures would be considerably lower than the hydrostatic pressure exerted by the column of drilling fluid it proposed to use.

CanOxy stated that the production phase for its well would be under the supervision of Petrogas and the existing emergency procedures plan established for the Balzac gas plant and associated field facilities.

When questioned regarding the need for an emergency procedures plan for all phases of its proposed operations, CanOxy indicated it would submit such an emergency procedures plan if the 10-22 well licence is granted. The applicant indicated that after approval of the plan by the ERCB,

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3 The device is designed in such a manner that if there was a failure in the facility control system, the valve would automatically close and remain closed until the facility's control system has been repaired.

the dangers of $H_2S$ and the emergency procedures plan would be explained to residents within the 3-km planning zone, in accordance with ERCB Interim Directive ID-OG-76-2[4], prior to spudding the proposed well.

## 7.3 Views of the Board

The Board recognizes that formation pressures and drilling practices in the general area have been well established and believes that the proposed wells could be drilled in compliance with Board regulations with a very low degree of risk and without seriously impacting the area residents.

The Board has reviewed the emergency procedures and design features proposed by ICG for the drilling, completion, standing, and production phases of its proposed 13-23 well and notes only minor deficiencies which must be rectified before the emergency procedures plan can be approved.

Regarding CanOxy's proposed well, if the well is to be drilled, the Board considers it necessary for CanOxy to have in place an approved sour gas emergency procedures plan to cover all phases of the proposed operations. The Board notes that CanOxy referred to the existing Petrogas emergency procedures plan for the production operations of the well but that an emergency plan was not submitted for the proposed 10-22 well's other stages. This would be required before drilling would be allowed to begin. Additionally, the Board would require the applicant to inform the public of the hazards of $H_2S$ and explain the emergency procedures plan prior to the commencement of drilling. The Board is, for the most part, satisfied with CanOxy's emergency procedures plan for the production phase of the 10-22 well where the existing Petrogas gas plant plan provides for the safety of the area residents on a priority basis in the event of an emergency.

In summary, the Board is satisfied that its regulations governing the completion, stimulation, clean-up, and initial testing operations of sour gas wells are adequate and is prepared to grant licences for the two wells. Drilling of the wells would be subject to satisfying the previously mentioned requirements respecting emergency procedures plans.

The Board acknowledges that the proposed wells would cause some nuisance and inconvenience to adjacent landowners. Experience indicates that the major source of complaint from residents in the general area under consideration arises from post-stimulation clean-up and initial testing operations at well sites. As a result, the Board

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4 Energy Resources Conservation Board, 1976. Emergency Procedure Plans For Sour Gas Facilities. ERCB Interim Directive No. ID-OG-76-2, Calgary, Alberta. ID-OG-76-2 requires notification of all residents within the maximum potential 100 ppm $H_2S$ isopleth from a sour gas facility. ICG has calculated this distance to be 3 km.

believes it would be appropriate for ICG and CanOxy to investigate alternative methods of stimulating and evaluating the subject wells should they be successfully drilled to the Crossfield Member. Any clean-up and test procedure would require Board approval.

## 8 NEED FOR AND ROUTES FOR THE PROPOSED PIPELINES

If the proposed 10-22 and 13-23 wells are successfully completed, the appropriate pipeline(s) will be needed to deliver the gas to processing facilities and thus to market. The Board notes that CanOxy has a gas sales contract with Petrogas for gas from the 10-22 well and that ICG has arrangements with Petrogas for the transportation, processing, and sale of gas from 13-23.

The Board considers the applied-for pipeline routes to be acceptable. It notes, however, that if both the proposed 10-22 and 13-23 wells are successful, the ICG pipeline would not be built. Also, if only the 10-22 well was successful there would be a change in routing for the pipeline from that well. Due to these uncertainties, the Board would condition any pipeline permits issued to require ICG and CanOxy to report to it and justify the need for the particular pipeline configurations before the lines were built.

## 9 POTENTIAL $H_2S$ RELEASE LEVELS

The Board recognizes the Fletchers' concern regarding development restrictions from the proposed Petrogas Level 2 pipeline and notes that the concern would be alleviated if the potential $H_2S$ release volumes were limited such that the subject pipeline would be a Level 1 facility. The Board notes that the Fletchers wish, at the same time, for the 13-23 well to proceed in order for them to gain direct royalty income. The fact that the well would be a Level 2 facility would nullify perceived advantages of a Level 1 Petrogas pipeline for parts of the Fletcher lands. The Board also notes that the sectionalizing emergency shut-down valves, needed to reduce the pipeline's potential $H_2S$ release volumes to Level 1, would be above-ground, thus having an impact on surface land use, would increase somewhat the potential for third-party damage, and would add to the cost of the project.

While a Level 2 well or pipeline may result in some land development restrictions, the Board believes that country residential subdivision, similar to existing subdivision in the immediate area, would not be precluded by either the 13-23 well or the Petrogas gas gathering pipeline.

Considering all aspects of the matter, the Board does not consider that restricting the proposed Petrogas pipeline to a Level 1 classification is warranted.

# 10 DECISION

## The ICG Applications

830167

The Board grants the well licence application of ICG to drill a well in Lsd 13-23-27-29 W4M subject to all the normal licence conditions and to the undertakings given by ICG at the hearing.

830165 and 830166

The Board grants the applications for pipeline permits but will condition them to prohibit their construction until their need has been confirmed by the evaluation of the 10-22 and 13-23 wells.

## The CanOxy Applications

830461

The Board approves the establishment of a special drilling spacing unit for fractional section 22 with the target area in accordance with section 4.020(3) and (4) of the Oil and Gas Conservation Regulations, as if the fractional section were a normal one section gas well drilling spacing unit.

830460

The Board is prepared to grant a licence to CanOxy to drill the proposed well in Lsd 10-22-27-29 W4M. The well licence would be issued subject to all normal Board regulations and also to the following special provisions:

a) CanOxy is required to submit prior to drilling, its emergency procedures plan elaborating on the details of the plan as it relates to the drilling, completion, stimulation, clean-up, initial testing, and standing phases of the proposed well,

b) CanOxy is required to make all residents within the 3-km planning zone aware of the hazards and characteristics of $H_2S$ and explain its emergency procedures plan prior to drilling.

The Petrogas Applications

830488 and 830489

The Board grants the applications for pipeline permits but will condition them to prohibit their construction until their need has been confirmed by the evaluation of the 10-22 and 13-23 wells.

DATED at Calgary, Alberta on the 29th day of July 1983.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy, P.Eng.
Vice Chairman

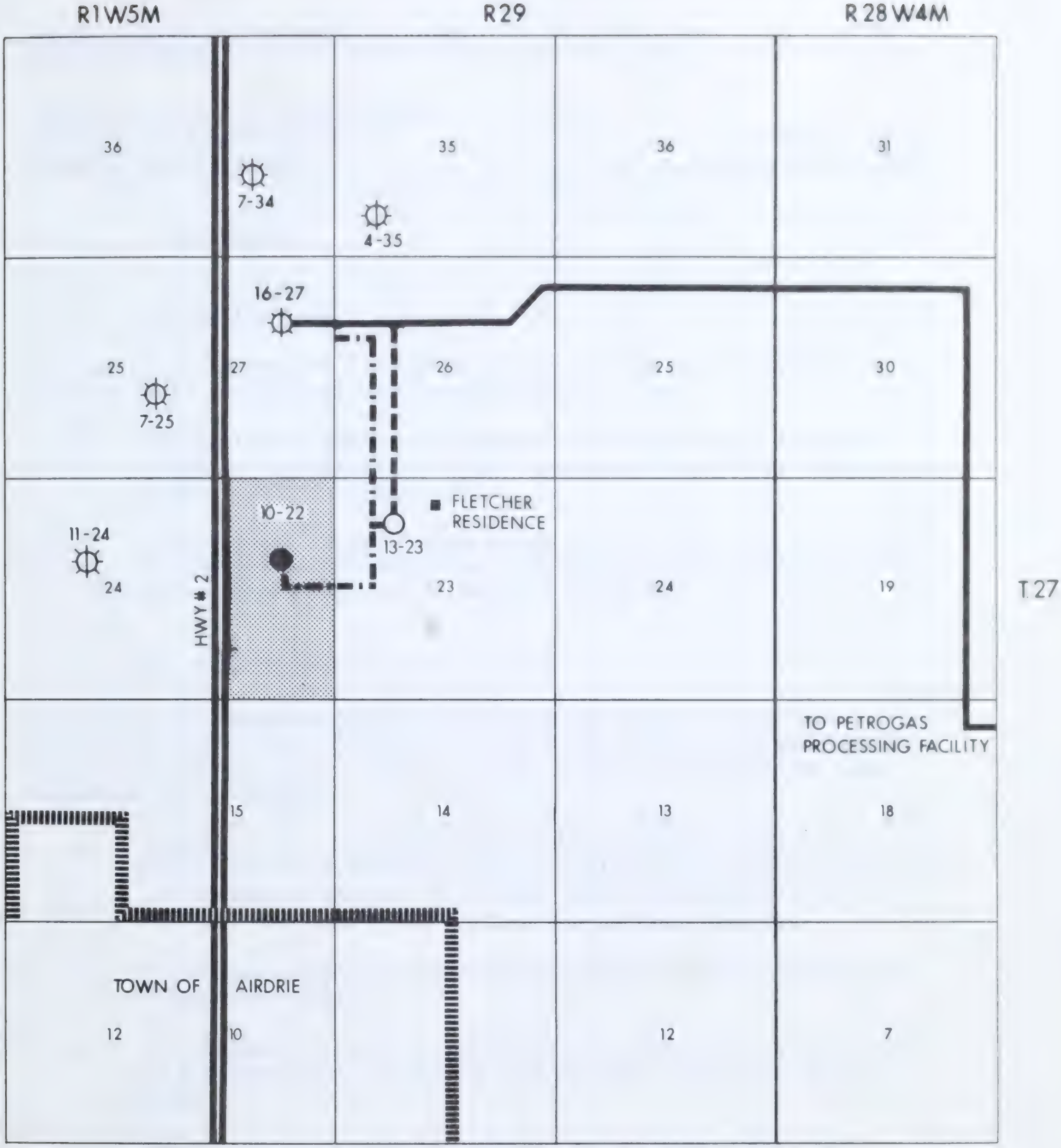
N. Strom, P.Eng.
Board Member

L. A. Bellows, P.Eng.
Acting Board Member

## THOSE WHO APPEARED AT THE HEARING

| Principals and Representatives (Abbreviations Used in Report) | Witnesses |
|---|---|
| ICG Resources Ltd. (ICG)<br>R. K. Laing | P. Krenkel, P.Eng.<br>J. K. Farries, P.Eng. of Farries Engineering (1977) Ltd.<br>R. B. Macpherson, P.Eng. of Farries Engineering (1977) Ltd. |
| Canadian Occidental Petroleum Ltd. (CanOxy)<br>A. L. McLarty | G. D. Simpson, P.Eng.<br>A. L. Hanson, P.Eng. |
| Petrogas Processing Ltd. (Petrogas)<br>A. L. McLarty | G. D. Simpson, P.Eng.<br>A. L. Hanson, P. Eng. |
| Austin Exploration Ltd. (Austin Exploration)<br>G. H. Austin | G. H. Austin, P.Geol.<br>N. P. McNally |
| Associated Engineering Services Ltd. (AESL)<br>I. Melland | |
| Mr. and Mrs. A. T. Fletcher (the Fletchers) | A. T. Fletcher<br>H. Fletcher |
| Energy Resources Conservation Board staff<br>C.J.C. Page<br>J. R. Nichol, P.Eng.<br>M. Semchuck<br>H. W. Knox, P.Eng.<br>W. E. Roberts, E.I.T. | |

Mrs. M. MacDonald and Mrs. A. Garland filed submissions but did not appear at the hearing.




EXISTING CANADIAN OCCIDENTAL PETROLEUM LTD. FUEL GAS & SOUR GAS LINES

PROPOSED ICG FUEL GAS & SOUR GAS LINES

PROPOSED PETROGAS FUEL GAS & SOUR GAS LINES

DRILLING SPACING UNIT— PARTIAL SECTION 22

GAS WELLS

PROPOSED ICG WELL

PROPOSED CANADIAN OCCIDENTAL PETROLEUM LTD. WELL

ICG RESOURCES LTD.
APPLICATIONS NO. 830165, 830166, 830167

CANADIAN OCCIDENTAL PETROLEUM LTD.
APPLICATIONS NO. 830460, 830461

PETROGAS PROCESSING LTD.
APPLICATIONS NO. 830488, 830489

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

CHEVRON CANADA RESOURCES LIMITED
APPLICATION FOR WATERFLOOD — Decision D 83-18
BIGORAY CARDIUM B POOL — Application 820632

# 1 INTRODUCTION

## 1.1 The Application

Chevron Canada Resources Limited (Chevron) has applied, pursuant to section 26 of the Oil and Gas Conservation Act, for

- o approval of a scheme for enhanced recovery of oil by water injection in the part of the Bigoray Cardium B Pool (B Pool) shown on the attached figure,

- o an amendment of subsisting Board Approval No. 3283 to delete the southwest quarter of section 3-51-9 W5M and the north half and southeast quarter of section 4-51-9 W5M.

## 1.2 The Intervention

J. M. Huber Corporation (Huber), as a working interest owner and operator in the B Pool, filed an intervention to Chevron's application for an enhanced recovery scheme. In its original intervention, Huber requested the following:

- o Injection into the well, CHEVRON PARA PEMBINA 10-34-50-9 (10-34 well), not be authorized until a satisfactory participation for the northwest quarter of section 34-50-9 W5M (NW 1/4 of 34-50-9) was negotiated between the parties involved.

- o The maximum injection wellhead pressure be limited to 11 000 kilopascals (kPa).

- o The southeast quarter of section 4-51-9 W5M (SE 1/4 of 4-51-9) be excluded from the scheme area and any subsequent project area.

- o The NW 1/4 of 34-50-9 be included in the scheme area and subsequent project area.

Based on an updated computer model study conducted by Intercomp Resources and Engineering Ltd. (Intercomp), Huber contended that Chevron's proposed scheme did not provide for the maximum recovery of oil and the application should therefore be denied.

## 1.3 Background

The B Pool was discovered in 1978 and has been developed on normal quarter section spacing. Currently there are nine producing wells in the pool.

In November 1980, Huber filed studies in support of an application for waterflooding showing that oil recovery from the pool could be optimized by implementing a line-drive waterflood, with water to be injected at the northwest and southeast ends of the pool. Huber applied to inject water into the well, HUBER BIGORAY 1-18-51-9, located in the northwest end of the pool, and stated that an injection location for the southeast end of the pool was not yet determined. Chevron filed an objection to the Huber application requesting that approval of the waterflood scheme be delayed until unit negotiations were completed. The Board was concerned that any significant delay in implementation of pressure maintenance would have a detrimental effect on oil recovery and granted the Huber application, issuing Approval No. 3283 for the scheme on 1 May 1981, as shown on the attached figure. Two special conditions were included in the approval, requiring that no production be taken from any production spacing unit (PSU) wherein the reservoir pressure is less than 8000 kPa (gauge) or from any well in the scheme wherein the producing gas-oil ratio (GOR) in cubic metres per cubic metre ($m^3/m^3$) is greater than 80. The approval area encompassed the then known limits of the pool and included both Huber and Chevron lands.

Huber subsequently received project status for its wholly owned lands, effective 1 November 1981, for the portion of the pool shown as Project 2 on the attached figure. Further, in accordance with its usual practice, the Board excluded the NE 1/4 of 7-51-9 W5M (drilled but non-productive) and the SW 1/4 of 17-51-9 W5M (undrilled) from the approved Project 2 area.

Chevron, on behalf of itself and Paramount Resources Limited, applied to amend Approval No. 3283, to delete its lands in the southeast part of the pool and assign them to a new separate waterflood area, with water to be injected in the southeast extremity of the pool at the 10-34 well. Notice for objection to the application was issued by the Board on 9 September 1982 and Huber filed a letter of objection on 1 October 1982.

## 1.4 Hearing and Appearances

A public hearing of the application was held on 21 December 1982, with N. Strom, P.Eng., J. A. Bray, P.Eng., Acting Board Member, and M. J. Bruni, Acting Board Member, sitting. Due to a request from the intervener, Huber, for more time to examine and respond to additional

information presented by the applicant, and also to consider the effect on Huber lands of injection into the 10-34 well, the hearing was adjourned and reconvened on 19 January 1983. After the conclusion of that sitting, the panel determined that there was still insufficient evidence before it to fully assess the application and hence, in a letter dated 17 February 1983, requested further information from Chevron. The hearing was reopened on 10 May 1983 to consider additional evidence filed by Chevron and Huber.

The following table lists appearances at the hearing.

THOSE WHO APPEARED AT THE HEARING

| Principals and Representatives (Abbreviations used in Report) | Witnesses |
|---|---|
| Chevron Canada Resources Limited<br>(Chevron)<br>R. A. Pashelka | K. Arthur, P.Geol.<br>R. A. Filgate, P.Eng.<br>C. B. Holmlund, P.Eng.<br>K. G. Matieshin, P.Eng.<br>P. W. Pantella, P.Eng.<br>(of Petresim Engineering Ltd.) |
| J. M. Huber Corporation<br>(Huber)<br>J. B. Ballem<br>T. M. Hughes | S. Collins, P.Eng.<br>H. V. Farmer, P.Geol.<br>E. F. Howard, P.Eng.<br>H. D. Noyes, P.Eng.<br>P. M. Stanton, P.Eng.<br>(of Intercomp Resource Development and Engineering Ltd.) |
| Energy Resources Conservation Board staff<br>B. E. Christensen<br>D. Holgate<br>K. Miller<br>K. G. Sharp, P.Eng. | |

## 2 ISSUES

The Board considers the principal issues respecting Chevron's application to be

- o geological nature of the pool
- o suitability of design of the proposed scheme
- o area of approval
- o appropriate terms of approval

## 3 GEOLOGICAL NATURE OF THE POOL

### 3.1 Views of Chevron

Chevron interpreted the pool to be a narrow conglomerate bar consisting of a good quality central portion which degrades laterally to become thin and tightly cemented towards the edges of the reservoir. It considered the determination of the pool edges and the quality along those edges to be highly interpretational. It observed that the recent extension of the pool to the southeast has shown the area of application to be more or less a mirror image of the Huber operated areas in the northern portion of the pool.

According to Chevron, Huber's well in the NW 1/4 of 34-50-9, HUBER PEMBINA 13-34-50-9 (13-34 well), does not meet either the porosity or permeability cutoffs which it normally assigns to wells in the reservoir and the well has not been recognized as having oil pay. Although Chevron recognized the presence of an undefined quantity of oil underlying Huber's tract in the NW 1/4 of 34-50-9, Chevron concluded that those reserves remain unproven.

On the other hand, Chevron's geological interpretation showed reserves underlying portions of its lands in SE 1/4 of 4-51-9 W5M (undrilled) and the NE 1/4 of 34-50-9 W5M (which includes the proposed 10-34 injection well). Chevron assigned oil pay to the 10-34 well based on demonstrated oil producing capability despite the fact that the reservoir at this location did not meet Chevron's permeability cutoff.

### 3.2 Views of Huber

Huber disagreed that the area of application is a mirror image of the northern portion of the pool. Specifically, it filed an updated Intercomp study which showed that regions in sections 34-50-9 W5M and 4-51-9 W5M contained poorer rock properties than the northern portion of the reservoir.

Huber estimated that the NW 1/4 of 34-50-9 contained approximately $111.2 \times 10^3$ $m^3$ of original oil-in-place and stated that its geological assessment, which did not apply porosity or permeability cutoffs, showed the 13-34 well to have 1.5 metres of oil pay. Although conceding that the 13-34 well has not been shown to be productive, Huber stated that it believes this well is in pressure communication with the reservoir.

Huber did not dispute Chevron's geological interpretation, that there are reserves under the SE 1/4 of 4-51-9 and the NE 1/4 of 34-50-9.

### 3.3 Views of the Board

The Board observes that the rock properties decline in quality towards the edges of the reservoir and interpretation of the productive limits is quite subjective. Thus, the only real proof would be via drilling producing wells in each drilling spacing unit (DSU).

The Board concludes that, while the applicant and intervener both have mapped oil reserves underlying portions of the SE 1/4 of 4-51-9 and the NW 1/4 of 34-50-9, it has not been established that recoverable reserves are present and it is questionable that a well drilled to penetrate those reserves would be capable of producing, having particular regard for the unpredictable fall-off in rock quality toward the edges of the pool.

## 4 SUITABILITY OF DESIGN OF THE PROPOSED SCHEME

### 4.1 Views of Chevron

Chevron stated that its application is based on the previous model study conducted by Intercomp in 1980, which concluded that maximum oil recovery would be achieved by a line-drive waterflood with injection at each end of the pool. Recent drilling has identified the 10-34 well as being located at the southern extremity of the pool, and Chevron concluded that this represents the optimum location for an injector in its proposed scheme.

Chevron considered extrapolation of the results from the previous reservoir model study an appropriate method of forecasting the performance of the proposed waterflood.

Chevron believed that the proposed 10-34 injection well would have sufficient injectivity for the proposed scheme. It did not agree that a maximum wellhead injection pressure clause need be specified since propagation of a fracture from the poorer quality edge of the pool towards the better quality central area would eventually be limited by fluid leak-off. Thus, injection above the fracture propagation pressure would not have any detrimental effect on recovery.

In the event that the 10-34 well were later shown to be incapable of adequately replacing reservoir withdrawals, Chevron stated that it would evaluate an optimum location for a second injector. It speculated that the use of the current producing well, CHEVRON PARA BIGORAY 2-3-51-9, would be given primary consideration.

In response to Huber's suggestion that the 13-34 well be given consideration as an injector, Chevron concluded that the 10 000 $m^3$ of incremental oil recovery attributed to conversion of the 13-34 well to injection service would not be economic when weighed against Chevron's estimate of $400 000 to convert to injection.

### 4.2 Views of Huber

While Huber agreed that waterflooding is the optimum recovery mechanism in the B Pool, it concluded that, based on results from a hydraulic fracture stimulation study conducted by Intercomp, Chevron's 10-34 well would not possess adequate injectivity to replace voidage throughout the life of the scheme in the absence of either excessive injection pressures or production restrictions.

Based on the results from the updated Intercomp model study, Huber concluded that the proposed scheme did not represent the optimum waterflood in the area of application and, in addition, that extrapolation of the previous model study to Chevron's area of application was inappropriate. To support its position, Huber presented predictions showing that 10 000 $m^3$ of incremental oil could be recovered by including the 13-34 well as an injector in the proposed scheme. Huber estimated that approximately $100 000 would be required to convert its 13-34 well to an injector and in view of the anticipated incremental recovery, this expenditure could be economically justified.

Huber also stated that the Chevron application failed to recognize the rights of other owners in the pool. It contended that if the application were approved, 21 000 $m^3$ of oil would be swept from the NW 1/4 of 34-50-9 tract owned by Huber and would subsequently be recovered at offsetting Chevron wells. Approval of the application

would also virtually destroy Huber's bargaining position with respect to the inclusion of the NW 1/4 of 34-50-9 within any unit agreement which might be negotiated.

Therefore, Huber requested that the Board deny the application and suggested that the Board subsequently request a joint submission from Huber and Chevron, within a limited period of time, which more clearly defines the optimum waterflood in the area of application.

## 4.3 Views of the Board

The Board is generally satisfied that a line-drive waterflood is an appropriate depletion strategy for the pool. Additionally, the Board accepts that injection at the southeast extremity of the pool as proposed by Chevron would tend to promote maximum sweep-out of that end of the reservoir.

The Board shares Huber's concern that the 10-34 well's injectivity may not be adequate to replace voidage throughout the life of the scheme unless either unacceptably high injection pressures or production restrictions were introduced. However, the Board believes that this potential limitation can be satisfactorily resolved through suitable approval conditions as discussed in section 6.

The Board is of the opinion that sufficient evidence was presented at the hearing to question the technical and economic merits of using the 13-34 well as an injector in the scheme. Furthermore, considering the problem of interpreting the limits and quality of the outer edges of the pool, the Board doubts that additional simulation studies would, with any certainty, lead to a better waterflood design than that proposed by Chevron.

Respecting Huber's concern about the potential for displacement of reserves that may exist in the NW 1/4 of 34, the Board observes that those reserves are not recoverable by Huber in the absence of a producing well. Given Huber's statement that it has no plans to drill an additional well in the NW 1/4 of 34, the Board concludes that the proposed scheme would not have an adverse impact on Huber.

In summary, the Board believes that

- o the Chevron scheme is near optimum,
- o it is in the interest of conservation to implement that scheme as soon as practical,

- o the potential impact on Huber's interest in NW 1/4 of 34 cannot be established owing to the absence of a producing well in that DSU and also due to the great uncertainty about reservoir interpretation,
- o there is no sound basis to defer the application pending further studies.

## 5 AREA OF APPROVAL

### 5.1 Views of Chevron

Chevron stated that, in addition to DSUs shown to be productive by drilled and producing wells, the undrilled SE 1/4 of 4-51-9 tract should be included in the scheme area. This was based on Chevron's geological interpretation that the SE 1/4 of 4 contains recoverable reserves which can be produced by offsetting producers in the proposed waterflood.

### 5.2 Views of Huber

Huber stated that the SE 1/4 of 4-51-9 should be excluded from any project for which Chevron might, in future, apply for inclusion since this tract could not be validated by application of the PSU rules. Huber contended that the exclusion would be consistent with the Board's exclusion of the NE 1/4 of 7-51-9 and SW 1/4 of 17-51-9 from Huber's assigned project area.

Huber further suggested that the Board might indicate, if common ownership were to be obtained at some future date, whether the NW 1/4 of 34-50-9 would be suitable for inclusion in a project area, even though it may not fit the normal rules as outlined in section 5.160 of the Oil and Gas Conservation Regulations.

### 5.3 Views of the Board

The Board believes that to avoid any misinterpretation respecting non-validated acreage it would be advantageous, in this instance of competitive waterflooding, to confine the area of approval to only those DSUs which meet the validation rules. In accordance with its previous conclusions in section 3, the Board has decided that the SE 1/4 of 4-51-9 and NW 1/4 of 34-50-9 should not be included in the area of approval while the remainder of the DSUs applied for are acceptable.

## 6 APPROPRIATE TERMS OF APPROVAL

### 6.1 Views of Chevron

Chevron did not concur with the need for a specified maximum bottom-hole injection pressure as suggested by Huber.

### 6.2 Views of Huber

Based on its concern regarding the anticipated level of injectivity of Chevron's 10-34 well as discussed in section 4, Huber suggested that, if the application were to be approved, two special conditions should be included in order to maximize recovery

- a voidage replacement requirement, and
- a limitation on the permissible wellhead injection pressure, such that it not exceed the estimated bottom-hole fracture propagation pressure of 26 400 kPa.

### 6.3 Views of the Board

The Board believes that a specified limitation in the permissible wellhead injection pressure is desirable for the subject scheme to prevent inordinate fracture propagation to an extent that "fingering" and by-passing would occur. The Board concludes that the intervener's suggested maximum bottom-hole injection pressure of 26 400 kPa, equating to approximately 12 000 kPa at the wellhead, is reasonable.

Also the Board believes that minimum static reservoir pressure and maximum GOR controls applicable to producing wells, like those included in Approval No. 3283, would be appropriate.

## 7 DECISION

The Board has decided to grant the application and will issue an approval for the proposed scheme, subject to the following conditions:

a) No production shall be taken from any production well wherein the reservoir pressure is less than 8000 kPa (gauge) or the producing GOR is greater than 80 $m^3/m^3$, unless the Board, upon application, otherwise permits.

b) Injection of water for the scheme shall be through the well, CHEVRON PARA PEMBINA 10-34-50-9.

c) The maximum wellhead injection pressure shall not exceed 12 000 kPa (gauge).

d) The approval area will include N 1/2 of 4, S 1/2 of 3-51-9, and NE 1/4 of 34-50-9 W5M.

The Board will make the appropriate amendments to the approval area for Huber's Approval No. 3283 to reflect the revised status resulting from this decision.

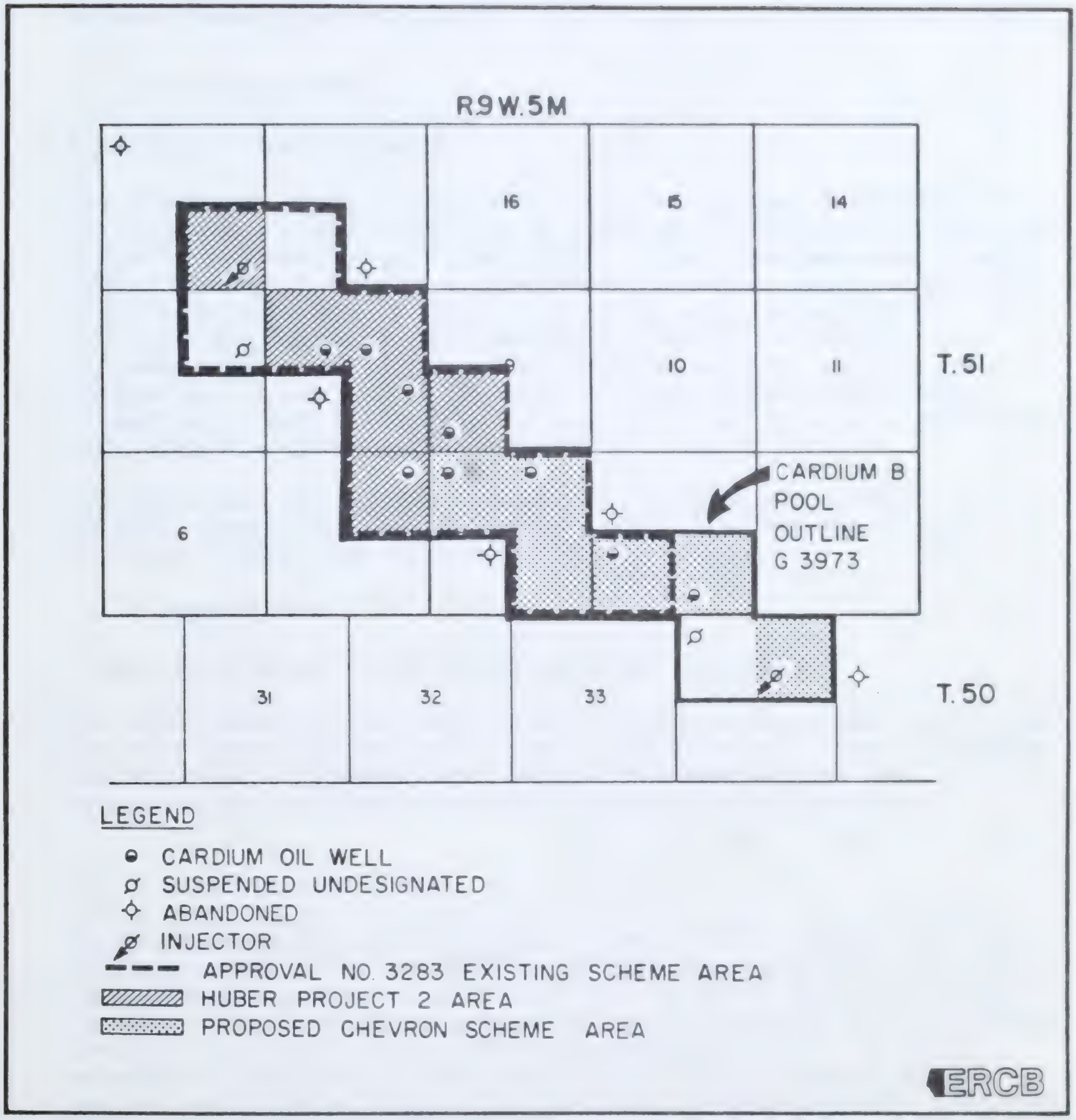
DATED at Calgary, Alberta, on 22 July 1983.

ENERGY RESOURCES CONSERVATION BOARD

N. Strom, P.Eng.
Board Member

J. A. Bray, P.Eng.
Acting Board Member

M. J. Bruni
Acting Board Member




BIGORAY CARDIUM B POOL

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

ESSO RESOURCES CANADA LIMITED
HYDROCARBON MISCIBLE FLOOD
JUDY CREEK BEAVERHILL LAKE A POOL

Decision D 83-19
Application No. 830246

# 1 INTRODUCTION

## 1.1 Application and Hearing

Esso Resources Canada Limited (Esso) applied, pursuant to Section 26 of the Oil and Gas Conservation Act, to implement a hydrocarbon miscible flood in the Judy Creek Beaverhill Lake (BHL) A Pool. Esso expected to begin solvent injection in mid 1985 and estimated the scheme would recover 0.06 of the initial oil volume in place or 7.8 million cubic metres ($10^6m^3$), over and above what would be recovered by the existing waterflood. The proposed scheme would involve the injection of solvent and chase gas volumes of 0.15 and 0.20 of the continuous hydrocarbon pore volume, respectively. Both the solvent and chase gas would be injected alternately with water at a water-alternating-gas (WAG) ratio of 1.0.

The application was heard by the Energy Resources Conservation Board in Calgary, Alberta on 19 and 20 July 1983 with G. J. DeSorcy, P.Eng., N. Strom, P.Eng., and H. Antonio, P.Eng., sitting.

## 1.2 Appearances

Those who appeared at the hearing are listed in Table 1.

The Board received seven interventions respecting the subject application. Six interveners attended the hearing for the purpose of cross-examination and argument only, while Amoco Canada Petroleum Company Ltd. intervened for the added purpose of submitting certain evidence.

# 2 BACKGROUND

The Judy Creek BHL A Pool was discovered in 1959. The pool was highly undersaturated with an initial pressure of 24 300 kilopascals (kPa) compared to a bubble point pressure of 15 800 kPa. The initial oil volume in place was 130 x $10^6m^3$. Early performance of the pool indicated that the primary depletion mechanism was an inefficient solution-gas drive. In 1962, a waterflood, consisting of three water-injection wells completed in the aquifer, was installed to arrest the declining reservoir pressure. However, as the rate of pool production increased, pressure gradients developed, and the injection system was therefore expanded to include 24 additional flank and bottom-water injectors. In 1974, an inverted 9-spot pattern waterflood

consisting of 15 injectors was implemented in the relatively low permeability reef interior. In 1977, a line-drive waterflood was instituted in the southeast sector of the pool with the conversion of two additional injectors. Currently, the Judy Creek BHL A Pool is producing at an average daily oil rate of about 2400 cubic metres ($m^3$) and an average water-oil ratio of about 7.0 $m^3/m^3$. The cumulative oil recovery is 0.325 of the initial oil volume in place.

The Board has recently processed two submissions from Esso on the Judy Creek BHL A Pool. In 1979, Esso applied to the Board and obtained approval for a carbon dioxide ($CO_2$) miscible flood. However, subsequent studies conducted by Esso showed that the benefits of the proposed $CO_2$ flood could not justify the substantial capital investment. In 1982, Esso submitted a reserve study of the Judy Creek BHL A Pool and as a result the Board lowered the ultimate recovery factor for the waterflood from 0.50 to 0.42. This reserve study was based on a pattern-by-pattern decline analysis of the pool.

## 3 ISSUES

The Board believes that the main issues for consideration in this application are:

- The desirability of the project in the public interest.
- The incremental recovery.
- The design features and special conditions.
- The need for infill drilling.

## 4 THE DESIRABILITY OF THE PROJECT IN THE PUBLIC INTEREST

### 4.1 Views of the Applicant

Esso put forward several positive effects that the miscible flood project would have on Alberta, from both an economic and conservation point of view. It said that the Province of Alberta would benefit from the increase in royalty and taxes received, and that the public would benefit in terms of jobs for engineering, construction, and services. Esso emphasized that the project comes at a time when jobs and renewed economic activity are badly needed.

The project would also provide a market for surplus natural gas and ethane plus in the province. Esso submitted that the expected shortage of ethane near the turn of the century would be reduced by the gradual recovery of the solvent bank used in this scheme.

Esso stated that not only would the scheme recover an additional 7.8 x $10^6 m^3$ of oil, but it would also cause a net increase in available energy by recovering 2.1 $m^3$ of oil for every 1.0 $m^3$ of oil equivalent consumed. This

increased recovery would reduce Canada's requirements for foreign hydrocarbons. In addition, Esso submitted that both industry and the Province would benefit from the timely development of enhanced oil recovery technology.

Esso estimated that the incremental oil recovery of a $CO_2$ miscible scheme over the proposed hydrocarbon miscible scheme would be only 0.013 of the initial oil volume in place or $1.7 \times 10^6 m^3$, and this increment would not be sufficient to support the significantly higher costs of a $CO_2$ process. Esso went on to conclude that an ethane-based hydrocarbon miscible process is the most economically viable tertiary recovery scheme for the pool.

### 4.2 Views of the Interveners

All but two of the interveners stated that they had no objection to the implementation of a hydrocarbon miscible flood in the Judy Creek BHL A Pool. The remaining two interveners did not submit any objections regarding implementation of the project.

### 4.3 Views of the Board

The Board believes that the proposed scheme is in the public interest considering:

- o It would have the potential to increase valuable light oil supplies.
- o It would provide a relatively efficient use of the current surplus of ethane.
- o It would foster significant economic benefits to Alberta through construction operations and taxes.
- o It would promote sound resource management and utilization relative to industrial development and resource upgrading.

The Board recognizes that a $CO_2$ miscible flood has the potential to achieve more efficient displacement than that projected for the proposed hydrocarbon miscible flood. However, the Board accepts the probability of higher costs for $CO_2$ miscible flooding, and that this could lead to lower economic oil recovery. From a public interest view, the Board therefore sees no reason to delay implementation of the proposed ethane-based hydrocarbon miscible flood.

## 5 INCREMENTAL RECOVERY

### 5.1 Views of the Applicant

Esso estimated the incremental recovery of the miscible flood over waterflood to be 0.06 of the initial oil volume in place. Esso's estimate was based on recovery correlations developed from areal and vertical reservoir simulation studies. These correlations were then used in a "Forecast Model", which Esso contended rigorously honoured the reservoir description across the entire pool on a pattern-by-pattern and zone-by-zone basis. Esso also contended that this approach allowed it to completely reflect the

influence of important physical factors, including gravity override, residual oil saturation to waterflood, areal sweep efficiency of the solvent bank, and local variations in reservoir continuity. Esso emphasized that the assumptions were fully compatible with the pool's waterflood performance.

Specifically, Esso's estimate of incremental tertiary recovery reflected several factors as outlined below.

### 5.1.1 Continuity Model

Esso first reviewed the degree of reservoir continuity in the Judy Creek BHL A Pool, as set out in its 1979 $CO_2$ miscible flood application to the Board. At that time, Esso determined the average pool continuity to be 0.93. This value was based on two cross-sections of the pool, and was a contributing factor to Esso's estimate of 0.20 incremental oil recovery under $CO_2$ flooding. Since that time, the overall waterflood performance and extreme (8000 kPa) pressure differences between wells completed in the same zone caused Esso to conclude that pool continuity was not as extensive as had been interpreted.

In its latest study, Esso used a different continuity model (Figure 1), in which more than 5000 well pairs were considered. Continuity maps were then constructed for each zone in the reservoir, and from these Esso was able to construct continuous pore volume or floodable pore volume maps, which indicate that the average reservoir continuity is 0.68, far below the previously interpreted 0.93.

Referring to Figure 1, a key part of Esso's continuity model is the assumed floodable pore volume assigned to bed Ia. Esso agreed that its approach of using half of the thickness difference to determine continuous pore volume for a bed of varying thickness was very much a matter of judgment. Esso maintained that it had no problems correlating porous beds between wells despite having to sometimes rely on neutron logs alone. Esso developed a relationship between log and core porosities and used this when only logs were available. Esso submitted that while the current continuity model may not be completely representative, it places a great deal of confidence in the results.

### 5.1.2 Residual Oil Saturation to Waterflood (SORW) and Hydrocarbon Miscible Flood (SORM)

Esso estimated the SORW to be 0.25 of the pore volume. Esso submitted that this value was not directly calculated from field or laboratory tests, but is a judgement value based on Esso's knowledge of the waterflood performance and pool continuity. Esso contended that the 0.25 value is supported by the results of several single well tracer tests and a pressure core analysis, which give average SORW values of about 0.15 and 0.22, respectively. Esso acknowledged that results of laboratory coreflood tests give an average SORW of about 0.35. However, it contended that laboratory results tend to be high in a pool like the Judy Creek BHL A Pool

because it is a vuggy-type reservoir and core tests are difficult to do properly on vuggy cores.

Esso pointed out that using the waterflood recovery factor of 0.383[1] determined from well production decline analysis, and an SORW of 0.25 coupled with a continuity factor of 0.68, results in a volumetric sweep of 0.80 of the continuous hydrocarbon pore volume (CHCPV). Since a waterflood volumetric sweep of 0.80 appears reasonable when applied only to the continuous part of the pool, Esso submitted that this further supported its estimate of SORW.

Esso acknowledged that, while it would expect to see a wide variation in SORW throughout the reservoir owing to widely varying reservoir rock properties, it had no firm data on which to base such an interpretation. Thus, in its model studies, Esso assumed a constant SORW throughout the entire pool. Esso also stated that, of the factors affecting its prediction of 0.06 incremental recovery, SORW is probably known with the least amount of certainty, and has the greatest effect.

Esso assumed SORM to be 0.05 of the pore volume, although core flood tests it conducted resulted in an SORM of 0.03.

### 5.1.3 Cross-Sectional Model

To quantify the significance of gravity override, Esso constructed a 2-dimensional, cross-sectional model which simulated miscible displacement between two wells. These wells represented the injector and a corner well of a 259-hectare (ha), inverted 9-spot pattern. The model has 22 communicating layers, each 0.6 metres (m) thick. Rock properties were obtained from the geological model for Pattern 46 of the project, which has relatively good vertical continuity and would be likely to exhibit override.

In the model, a zone was defined as the region between permeability barriers. Case 1 used a permeability barrier between each layer to give 22 zones that were 0.6 m thick; case 2 had seven zones that were 1.8 m thick; case 3 had four zones that were 3.7 m thick; and case 4 had just one zone that was 13.4 m thick. The model was run for these four cases, and the results were used to generate a relationship between override recovery factor and zone thickness. The override recovery factor is the recovery obtained for a given zone thickness relative to the recovery obtained from a 0.6-m layer. Esso assumed that no override would occur in a 0.6-m layer. The override recovery factor versus zone thickness relationship was then a applied to Esso's zonation model in each pattern in the project area to determine each zone's average override factor. The results gave a pool average gravity override factor of 0.73.

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1 This value represents the waterflood recovery from the continuous portion of the pool. Esso attributed some primary recovery to the discontinuous portion of the pool, which results in a total pool recovery of 0.415.

The cross-sectional model used $CO_2$ properties for the solvent, but Esso contended that although a hydrocarbon solvent would have half the density of $CO_2$, the difference in flood performance was not expected to be significant.

Esso indicated that although the model used rock properties from Pattern 46, the override versus zone thickness relationship should be applicable to the rest of the pool. Esso submitted that by inserting vertical permeability barriers at various points throughout the 22 layers of the model, the permeability distribution was not the same between each barrier. Therefore, the override relationship is applicable for a variety of permeability distributions. Esso also stated that, although gravity override was not solely dependent on zone thickness, the overall impact of the other variables (fluid viscosities and densities, displacement rate, interwell distance) is not that significant.

5.1.4 Areal Model

Esso employed an areal model originally designed by Todd, Dietrich, and Chase (TDC) [2,3] to simulate the complex solvent-oil movements in the miscible flood. The TDC model allowed Esso to determine: areal sweep efficiency; breakthrough time for solvent, chase gas, and water; and the impact of different solvent bank sizes on recovery efficiency.

The model operates on a quarter of an inverted 5-spot pattern, using a single 0.6-m layer of the reservoir, and is divided up into a 15 by 15 grid. It assumes pseudo-immiscible slipping of the solvent past the oil to represent the unstable interface of the solvent-oil bank, which leads to viscous fingering. The degree of slipping or bypassing of the oil is controlled by the mixing parameter omega ($\omega$). As $\omega$ varies from one to zero, the displacement changes from a piston-like miscible flood to a completely immiscible flood. Esso chose an $\omega$ value of 0.7, as it had been shown to give a good history match for a number of $CO_2$ floods, agreed with the Koval/Claridge [4,5] approach, and was supported by the history matching of 7 corefloods of Redwater cores.

The TDC model was run for different solvent bank sizes ranging from 0.05 to 0.40 CHCPV, and the results were used to generate a relationship between tertiary oil recovery and CHCPV of injected fluid for each bank

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2 Todd, M. R. and M. R. Longstaff, "The Development, Testing and Application of a Numerical Simulator for Predicting Miscible Flood Performance", JPT, July 1972.

3 Chase, C. A. and M. R. Todd, "Numerical Simulation of $CO_2$ Flood Performance", SPE 10514 (1982).

4 Koval, E. J. "A Method for Predicting the Performance of Unstable Miscible Displacement in Heterogeneous Media", SPE Journal, June 1963.

5 Claridge, E. L., "Prediction of Recovery in Unstable Miscible Flooding", SPE Journal, April 1972.

size. The results indicated that tertiary recovery increased with bank size until, at 0.40 CHCPV bank size, essentially all of the SORW was recovered. These recoveries were for a single layer and did not account for effects due to gravity override, reservoir discontinuities, or vertical sweep efficiency.

### 5.1.5 Combined Forecast Model

In order to combine the results of the continuity model, cross-sectional model, areal TDC model, and waterflood decline analysis, Esso developed an empirical algorithm which it referred to as its Forecast Model. The results of the Forecast Model form the basis of Esso's incremental recoverable oil e timate (waterflood versus hydrocarbon miscible).

The model assumed the present waterflood fluid production would continue until the start of solvent injection, at which time the fluid production rates would increase to reflect workovers performed on all the wells.

The first step in the Forecast Model's procedure was to divide a given pattern into stratigraphic zones. The stratigraphic zones were then subdivided into 0.6-m layers, each having a value for porosity-thickness (Øh) and permeability-thickness (kh) assigned to it. The injected fluids were distributed to each layer in proportion to the layer kh.

Once the total fluid injection had been apportioned to each layer, the Forecast Model applied the Koval/Claridge correlations to determine the tertiary recovery for each layer. The tertiary recovery calculated using this method assumed that all the injected fluid was solvent, rather than a solvent bank followed by chase gas. Therefore, the next step in the Forecast Model's procedure was to reduce the layer tertiary recovery to account for the fact that continuous solvent injection did not occur. It did this by applying a "bank size adjustment factor", derived from the areal TDC model, to each layer. This factor accounted for the different solvent bank sizes occurring in separate layers.

The "adjusted" tertiary recovery for each layer was then reduced further by the "override factor", which accounted for gravity override effects. Each stratigraphic zone had a single, weighted-average override factor assigned to it. This average override factor was then applied to all the layers within the zone.

At this point, the tertiary recoveries for each layer were summed to give the tertiary recovery for the zone. The zone tertiary recoveries were then added together to give the total pattern tertiary recovery, and this was added to the pattern waterflood recovery to give the ultimate oil recovery for the pattern. This procedure was used for all the patterns in the project area to predict the ultimate oil recovery for the Judy Creek BHL A Pool.

Esso ran its Forecast Model for both a 0.15 and 0.20 CHCPV solvent bank size, and found that the oil recovery for the 0.20 CHCPV bank increased by only 0.007 CHCPV over that recovered by the 0.15 CHCPV bank. This gave only a marginal increase in the project value.

Esso submitted that the use of an inverted 5-spot pattern in the model, rather than the actual inverted 9-spot pattern which would be used in the field, should give slightly conservative recoveries (smaller by 0.003 of initial oil volume in place).

Esso also pointed out that in order to verify the Forecast Model against waterflood performance, the Model would have to be modified. However, Esso did not attempt to do so.

It also stated that a 3-dimensional model study was not considered because of the increased time and expense it would involve, and because the results would be no more accurate than Esso's present model.

5.1.6 Sensitivity Analysis

Esso performed a sensitivity analysis on the Forecast Model to illustrate the effects of reservoir continuity, SORW, and gravity override. It conducted this sensitivity analysis in a stepwise manner; first increasing the continuity to 1.0, then increasing the override factor to 1.0 with continuity still at 1.0, and finally increasing the SORW to 0.35 with continuity at 1.0 and override at 1.0. The results showed that if a continuity of 1.0 were assumed, the incremental recovery would increase from 0.06 to 0.09. If continuity were 1.0 and there was no gravity override, the incremental recovery would increase to 0.11. Finally, if continuity were 1.0 and there was no gravity override, and SORW was increased to 0.35, the incremental recovery would be 0.165.

Esso maintained that the results of this sensitivity analysis indicated that it is not any uniqueness of the Forecast Model itself which produces the overall 0.06 incremental recovery, but rather the underlying effects of continuity, override, and residual oil saturation.

5.1.7 Performance of Other Horizontal Miscible Floods

Esso submitted a commentary on the performance of other horizontal miscible floods. Its overall impression was that they all appeared to fall short of the initially predicted incremental recoveries of 0.20 or more. It believed these field results supported its prediction of a 0.06 incremental recovery in the Judy Creek BHL A Pool. Esso stressed however, that it was not implying that the magnitude of the incremental recovery predicted for the Judy Creek BHL A Pool should be applied to other miscible schemes in the province.

Esso observed that the central part of the Swan Hills South BHL A & B Pool, which is being miscibly flooded, is similar to the high productivity portion of the Judy Creek BHL A Pool waterflood project. It believed that the waterflood recovery of 0.51 to 0.54 for the Judy Creek high productivity area could by analogy be applied to the Swan Hills South miscible flood project area. Then, assuming a miscible flood recovery of 0.60 to 0.65 for the Swan Hills South project, Esso would calculate a range for incremental tertiary recovery between 0.06 and 0.14. After taking into account oil migration from the Swan Hills South West Waterflood area, which had been estimated by the operator to be 0.05 of the initial oil volume in place, the net incremental tertiary recovery would range from 0.01 to 0.09. Esso noted that its estimate of 0.06 incremental recovery for the geologically similar Judy Creek BHL A Pool was within the same range.

Esso questioned the comparison made by Amoco between the results of the Slaughter Estate Unit tertiary $CO_2$ pilot in West Texas and the Judy Creek BHL A Pool miscible scheme. Esso argued that if its scheme had 1.2-ha spacing rather than an average 64-ha spacing, and if the pool had continuous, homogeneous layers with very little permeability variation, Esso would expect an incremental recovery in the order of 0.20.

5.2 Views of the Interveners

Most of the Interveners indicated that they considered Esso's incremental recovery factor of 0.06 to be on the low side.

Only Amoco and Home had comments concerning the waterflood recovery factor of 0.415. Amoco stated that it expected waterflood recoveries in the Beaverhill Lake pools to vary from 0.30 to 0.40. Amoco also questioned Esso's pattern-by-pattern decline analysis, stating that it is affected by oil migration between patterns. Both Amoco and Home suggested that a better approach would be to do the decline analysis on a pool-wide basis.

Concerning Esso's miscible flood prediction method and results, the interveners expressed the following views.

5.2.1 Continuity Model

Amoco stated in its submission that there are discrepancies between Esso's continuity model and that presented by Stiles[6] or by Delaney and Tsang[7]. As a result, the same basic well data can give widely varying continuity values depending on the model used. In addition, Amoco submitted that the zonal picks and correlations between wells contain a considerable subjective element. Amoco concluded that the continuity model's validity had not been established by Esso, and that a better explanation for the poor waterflood performance in the Judy Creek BHL A Pool might be that SORW is higher than 0.25.

6 Stiles, L. H. and C. J. George, "Improved Technique for Evaluating Carbonate Waterfloods in West Texas", SPE 6739 (1977).

7 Delaney, R. P. and P. B. Tsang, "Computer Reservoir Continuity Study at Judy Creek", Journal of Canadian Petroleum Technology, Jan.-Feb. 1982.

Gulf suggested that the discontinuities, attributed by Esso as being responsible for the poor waterflood performance, could actually be due to relative permeability effects. If so, the so-called discontinuous portion of the reservoir might respond to miscible fluid displacement, whereas it would not accept water intrusion. This would mean that the incremental recovery could actually be much larger than Esso had predicted.

In its closing remarks, Dome stated that the continuity model was based solely on well geology, and should have been verified by history matching the waterflood performance.

### 5.2.2 Residual Oil Saturation to Waterflood (SORW) and to Miscible Flood (SORM)

Most of the interveners indicated that Esso's estimated SORW of 0.25 was too low. They suggested that the reservoir continuity and SORW are linked, and that it would remain consistent with waterflood performance if both values were increased.

Gulf noted that an SORW of 0.25 implied a volumetric sweep efficiency of about 0.80, which would require that the areal and vertical sweep efficiencies be about 0.90 each. Gulf considered that these were unusually high sweep efficency values even for connected pay zones, and that this implied the SORW should be higher.

Mobil pointed out that the results of the tracer and pressure core tests, which Esso used as partial support for its 0.25 SORW, had been down-rated in the ERCB 1974 Examiner's Report[8].

Amoco disagreed with Esso's statement that laboratory coreflood tests will give high values of SORW. Amoco submitted that due to the small plug size, high pressure gradients, and high throughputs, laboratory SORW values were more likely to be lower than those actually occurring in the field.

Dome stated in its closing remarks that SORW should be between 0.30 and 0.35, but had no calculations to support that opinion.

### 5.2.3 Cross-Sectional Model

Amoco submitted it was improper to use the rock properties from Pattern 46 to try to simulate gravity override effects in other patterns that have quite different rock properties. Amoco also noted that the fluid properties used in the cross-sectional and the areal models were quite different.

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8 "Report of Examiners", Application No. 6984, 21 February 1974.

Shell contended that Esso's cross-sectional model did not properly account for the effects of solvent density, interwell distance, variation in rock properties, or flow rate in determining gravity override. Shell further indicated that Esso could not judge the relative impact of these factors on override without first doing sensitivity runs with its model.

5.2.4 Areal Model

Amoco submitted that since the areal model used an inverted 5-spot pattern rather than an inverted 9-spot, which is being used in the miscible project, the applicability of the model results is questionable.

Chevron suggested that in the areal model, the $\omega$ factor strongly affects recovery, yet Esso determined the value of $\omega$ from scientific literature and corefloods from other pools, rather than on actual pool data from Judy Creek.

5.2.5 Combined Forecast Model

Several interveners suggested that a 3-dimensional model would have given more accurate results than Esso's combination of areal and cross-sectional models. Mobil and Gulf indicated that the Forecast Model may be accounting for some effects more than once, and they suspected the results are pessimistic.

Dome noted that the Forecast Model calculates the effects of override and bank size separately, when in fact the solvent bank size in each layer will change depending on the cross flow or override. Also, the Forecast Model assumes that there is an SORW of 0.25 distributed uniformly throughout the continuous part of the pool, and this would be erroneous if water slumping during the waterflood had left the upper portion of the reservoir unswept. This unswept section would likely be contacted by the tertiary miscible flood owing to override effects, causing the reservoir to be preferentially miscibly flooded in the upper portion and preferentially waterflooded in the lower. Dome suggested that Esso could strengthen its areal and cross-sectional models by running a 3-dimensional model in some patterns and using the results to adjust the 2-dimensional models. Dome also submitted that the accuracy of the Forecast Model should have been verified by history matching with the waterflood performance.

5.2.6 Performance of Other Horizontal Miscible Floods

Amoco agreed with Esso's 0.55 to 0.60[9] projected ultimate recovery under miscible flood for the Swan Hills South BHL A & B Pool. Using

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9 Esso initially projected an ultimate recovery of 0.60 to 0.65, but then subtracted 0.05 to account for oil migration into the project area.

a plot of breakthrough ratio versus cumulative production, which gave a recovery factor of 0.555, and then adding 0.015 to account for the recovery during the final waterflood stage, Amoco determined the ultimate recovery to be 0.57.

Amoco stated that it did not agree with Esso's 0.51 to 0.54 waterflood recovery attributed to the high productivity area in the Judy Creek BHL A Pool, nor that the area was analogous to the central part of the Swan Hills South BHL A & B Pool miscible flood area.

Amoco further submitted that, assuming 0.35 SORW, Esso's high estimate of waterflood recovery for the Swan Hills South miscible flood area would result in unreasonably high values for volumetric sweep efficiency. In fact, if continuity were assumed to be less than 0.89 and SORW to be 0.35, the volumetric sweep would have to be above 1.0. Amoco stated that it believed the central part of Swan Hills South BHL A & B Pool miscible flood area would have recovered between 0.42 and 0.45 of the initial oil volume in place under waterflood. When compared to the 0.57 estimated recovery under the miscible flood, this gives an incremental recovery of 0.12 to 0.15. Amoco concluded that in the past many miscible flood schemes have been failures, but maintained that some have done well and that the failures can be attributed to poor design and operation of the schemes.

To further support its argument for a larger incremental recovery, Amoco cited the Slaughter Estate Unit tertiary $CO_2$ pilot in West Texas, which shows that incremental recoveries of 0.20 to 0.25 are possible under the WAG process. In addition, Amoco pointed out that tests performed on the well located in Lsd 2-20-65-10 W5M in the Swan Hills South BHL A & B Pool indicate that the vertical sweep efficiency of the miscible flood scheme is excellent.

### 5.3 Views of the Board

It is evident that Esso has conducted a thorough analysis of both the current waterflood operation and its expectations from the proposed tertiary hydrocarbon miscible flood project. The Board considers the pattern decline analysis a valid basis for projecting waterflood performance and continues to accept the recently adopted waterflood recovery factor of 0.42 for the Judy Creek BHL A Pool. The Board, nevertheless, believes that Esso's tertiary recovery predictions are open to question in a number of respects. The Board's views respecting the key factors follow.

#### 5.3.1 Continuity Model

Considering the nature of the reservoir and the observed performance, the Board agrees that the Judy Creek BHL A Pool does have substantial discontinuities. However, the Board believes there are inherent difficulties in attempting to quantify the extent of the discontinuities. The task of

correlating zones between wells, and the method of quantifying continuity between wells, introduces a considerable margin of interpretation. Unlike Esso, the Board is of the opinion that the degree of reservoir discontinuity and its effect on the incremental recovery prediction is as much uncertain as the degree of influence and potential variation of SORW.

The Board particularily notes the variations in continuity estimates that can occur depending on the model that is used. For instance, of the three different choices of continuity models identified by Amoco, the one used by Esso gives the lowest estimate of continuity. In addition, the Board agrees with Gulf's suggestion, that because of the complex nature of the reef and the variation in rock wettability properties, the concept of continuity could be different for water than for hydrocarbon displacement fluids. Considering all possibilities, the Board is inclined to believe that the reservoir continuity is somewhat higher than Esso's value of 0.68.

5.3.2 Residual Oil Saturation to Waterflood (SORW) and Hydrocarbon Miscible Flood (SORM)

The Board accepts that it is very difficult to determine an average SORW for the Judy Creek BHL A Pool, since for the complex carbonate rock SORW would likely vary quite widely.

The Board has reviewed the different sources of information on SORW for the BHL pools in the Judy Creek area:

- o Coreflood tests conducted on restored-state cores using stock tank oil.

- o Coreflood tests conducted on restored-state cores using reservoir oil.

- o Preserved cores from water-swept areas (pressure cores).

- o Single-well tracer tests.

- o Conventional cores (water-based cores).

When studying conventional cores, it was assumed that the cores had been effectively "waterflooded" by the fluid circulation in the wellbore during the coring process. After allowing for losses due to shrinkage and bleeding, the measured values of oil saturation were assumed to represent SORW.

The Board notes that the above sources of information give a wide range of SORW values. The preserved cores, single-well tracer tests, and conventional cores give average SORW values ranging from 0.15 to 0.25. Coreflood tests conducted on restored-state cores using reservoir oil give SORW values ranging from 0.15 to 0.35. Coreflood tests conducted on restored-state cores using stock tank oil give SORW values ranging from 0.30 to 0.40.

For reasons outlined in its 1974 Examiner's Report, the Board believes that both the preserved cores and single-well tracer tests probably give SORW values that are lower than the average SORW in the Judy Creek BHL A Pool. With respect to the coreflood tests on restored-state cores, the Board believes that the wettability of the cores can be altered by the procedures used to prepare the cores for waterflood tests. In addition, the use of stock-tank oil can introduce different interfacial tension and mobility effects then would be the case in the reservoir.

As a result of the review conducted, the Board concludes that the most representative value of the average SORW in the Judy Creek BHL A Pool is approximately 0.30 of the pore volume.

### 5.3.3 Cross-Sectional Model

The Board believes that the 2-dimensional, cross-sectional model used by Esso to generate a relationship between zone thickness and gravity override is in itself a valid approach. However, the Board believes that while zone thickness may have the greatest effect on override, other factors such as solvent density, interwell distance, and flow rate will also have an influence. In addition, the Board is concerned that by using rock properties from a pattern with higher than average vertical permeability and continuity, and applying the results to the entire pool, the model may be overstating the potential for override.

### 5.3.4 Areal Model

The Board believes that Esso's areal TDC model is a valid method of determining areal sweep efficiencies, breakthrough times, and solvent bank size effects on recovery. The Board is concerned however, that Esso's choice of 0.7 for the mixing parameter, $\omega$, will apparently have a significant influence on the model results, yet is difficult to verify. The relationship between solvent bank size and tertiary recovery generated by the model, nevertheless, illustrates the need for sufficient solvent to accommodate the instabilities in the flood front.

### 5.3.5 Combined Forecast Model

In the Board's view, Esso's Forecast Model honours the reservoir description across the entire pool and reflects many of the physical processes involved in miscible displacement. However, since continuity, areal and vertical sweep efficiencies, gravity override, and bank-size effects are not fully independent of one another, it is conceivable that by determining them independently and then combining them, the Forecast Model may tend to overcompensate for some effects.

The Board would have more confidence in the Forecast Model if some form of verification had been attempted by Esso, such as modifying the model to predict waterflood recoveries and checking the results against the waterflood decline analysis, or running a 3-dimensional miscible flood simulator on selected patterns and comparing the results with the Forecast Model's predictions.

5.3.6 Performance of Other Horizontal Miscible Floods

The Board agrees with Esso that a number of miscible flood schemes have failed to live up to initial recovery predictions, and to some extent this would support Esso's expectation of a relatively low (0.06) incremental recovery for the proposed Judy Creek project.

The Board believes that, with respect to pool geology, the high quality portion of the Judy Creek BHL A Pool and much of the Swan Hills South miscible flood area are similar, and it is reasonable to assume waterflood recoveries would be similar. However, the Board considers Esso's interpretation of the waterflood recovery in the high productivity area of Judy Creek BHL A Pool (0.51 to 0.54) to be on the high side. The Board's belief is that waterflood recovery for the Swan Hills South miscible flood area and for better parts of Judy Creek would be around 0.45. Also, the Board accepts Amoco's preliminary projections that indicate an ultimate recovery of 0.57 for the Swan Hills South miscible flood. This rationale would indicate that incremental tertiary recoveries in the high quality portions of Judy Creek and Swan Hills South would be around 0.12.

The Board regards the other field examples referred to by Esso and Amoco as not informative to reaching a conclusion respecting incremental recovery for the Judy Creek BHL A Pool.

5.3.7 Summary

Considering all aspects of the interpreted reservoir properties, reservoir fluid displacement properties, and waterflood performance, the Board concludes that reservoir continuity is probably in the range of 0.75 to 0.80. In addition, the Board considers an SORW value of 0.30 to be appropriate and also agrees that an SORM of 0.05 makes reasonable allowance for solvent flood pore-contact inefficiencies.

Regarding the combined miscible flood performance prediction (ie the Forecast Model and the separately determined inputs to it), the Board believes that there is a possibility of modest overcompensation for some of the instability effects that are characteristic of any horizontal miscible flood.

Taking Esso's incremental recovery of 0.06 as determined by the Forecast Model, and incorporating the above adjustments, the Board concludes that the incremental recovery for the applied-for scheme will be approximately 0.09 of the initial oil volume in place. This, added to the waterflood recovery of 0.42, results in an ultimate pool recovery of 0.51 of the initial oil volume in place ($66.3 \times 10^6 m^3$).

# 6 DESIGN FEATURES AND SPECIAL CONDITIONS

## 6.1 Views of the Applicant

The important design features of the miscible scheme are outlined below.

### 6.1.1 Solvent Composition

Esso's solvent composition was designed to be first-contact miscible with the reservoir oil at the proposed operating pressure of 24 130 kPa. This ensures a safety margin of 7 to 8 mole per cent of ethane plus ($C_2$+) before the immiscible region is reached. Esso did not submit a single solvent composition, since it expects the supply source composition of $C_2$+ to vary with time. To allow for this variation in composition, Esso determined a relationship which shows the $C_2$+ concentration needed in the solvent for a given $C_2$+ molecular weight, for first-contact miscible displacement. This relationship is shown in Figure 2, and will allow Esso to properly mix the $C_2$+ and methane so that the solvent is always first-contact miscible.

Esso explained that the mixing of the $C_2$+ and methane will be controlled by a mini-computer located at the blending point. Esso also stated that it expects the chase gas to be miscible with all solvent compositions.

### 6.1.2 Bank Sizes and WAG Ratio

Esso proposed to inject into each pattern a solvent bank volume equal to 0.15 CHCPV and a chase gas bank of 0.20 CHCPV. In accordance with the WAG program, injection of hydrocarbons would be alternated with water on approximately a six to eight week interval, having a WAG ratio of 1.0 after each cycle is completed. Esso submitted that the operator of the geologically similar Swan Hills South miscible project found from experience that the optimum WAG ratio for its miscible flood was 1.0, and therefore Esso would initially use that ratio. It may however, be altered as dictated by operating field experience or water handling capacity. If sufficient water handling capacity cannot be found, the WAG ratio may have to be increased to as high as 3.0 or 4.0 in some patterns. However, Esso did not foresee any problems with this possibility since corefloods conducted at a WAG ratio of 5.0 showed no detrimental effects.

Esso indicated that if performance of the scheme demonstrated that the CHCPV was larger than shown by its continuity model, it would make appropriate adjustments during solvent bank injection to ensure that it achieved the target bank size of 0.15 CHCPV.

Esso also stated that it expects the mobility ratio under the WAG process to be about 2.0, and that it had not considered other methods of mobility control.

### 6.1.3 Injection Strategy

Esso plans to use 54 injectors to miscibly flood 50 patterns across the pool. This injection will alternate between water and solvent/chase gas at six to eight week intervals. The solvent injection will be confined to certain areas of the pool to begin with and will be expanded to other areas according to the schedule given in Table 2 and the area maps in Figures 3 and 4. Esso estimated that the total time for solvent injection would be 10 years, but that the injection strategy may change once solvent breakthrough occurs. Esso also submitted that the solvent injection rate could vary from about 1.4 million cubic metres per day ($10^6 m^3/d$) to 2.1 x $10^6 m^3/d$, depending on the $C_2$+ availability and composition, potential requirements of the Judy Creek BHL B Pool, and the water disposal capacity external to the Judy Creek BHL A Pool. The solvent/chase gas and water will be distributed in separate systems. Main distribution lines will deliver the solvent/chase gas from a central pumping facility to the regional injection well feed locations.
To meet a voidage replacement ratio of 1.0, the remainder of the existing fresh water injection system will be converted to handle produced water.

Esso believes that it can monitor the solvent bank movement even though some patterns will be injecting chase gas while others will be injecting solvent . Esso's reason for following the proposed injection strategy is to gain experience in the reef framework and then in the lagoonal area, before expanding to the entire pool.

### 6.1.4 Well Monitoring and Completion Strategy

Esso submitted that monitoring of the miscible flood will be aimed at maximizing both the areal and vertical sweep efficiency. Areal sweep efficiency will be defined and controlled by pressure surveys and voidage balancing, respectively. Injection/production profiles will be monitored periodically to determine zonal or vertical sweep. Well pressures and compositional analyses to determine flood movement will be evaluated on a quarterly basis. Esso intends to initially inject into all hydrocarbon bearing zones, and as certain zones are depleted, the injection will be limited to the effective producing zones by mechanical means in the wellbore. The periodic monitoring of injection/production profiles in the wellbore will identify zones that need either selective acidizing to increase injection, or mechanical shutoffs once they are depleted.

Esso stated that it plans to handle high water production by selectively shutting in high water-oil ratio (WOR) wells or zones, and by possibly increasing the capacity of one of the disposal wells by installing a booster pump, which would give an extra 3000 to 5000 $m^3/d$ of disposal. Esso is currently examining the Upper Mannville and Glauconitic zones for possible uphole water disposal. Esso also stated that it expects good success in selectively shutting off high WOR zones in wells with good cement bonds, using packers and sliding sleeves.

## 6.2 Views of the Interveners

Amoco suggested that the solvent and chase gas bank sizes may be underdesigned if the continuity is greater than expected.

The interveners had no other comments concerning the flood design.

### 6.3 Views of the Board

#### 6.3.1 Solvent Composition

The Board finds Esso's plan to inject solvent of varying composition acceptable, provided it is always sufficiently rich to achieve first-contact miscibility as reflected in the relationship given in Figure 2.

#### 6.3.2 Bank Sizes and WAG Ratio

The Board is concerned that Esso's solvent and chase gas bank sizes may be underdesigned, since they are based on CHCPV. The Board is of the opinion that Esso's continuity model is conservative and therefore believes that the solvent and chase gas banks will be somewhat less than 0.15 and 0.20 of the CHCPV, respectively. The Board will therefore require that Esso submit a re-evaluation of the bank designs within 4 years of commencement of the solvent injection, or earlier if performance has clearly indicated the need for a change in design size.

#### 6.3.3 Injection Strategy and Completion Strategy

Ideally, the Board believes that the most sound form of flood control would be achieved if solvent injection was applied simultaneously in all patterns, so that migration effects that are exacerbated by higher permeability regions are kept to a minimum. However, the Board accepts the program as submitted by Esso with the qualification that, if abnormalities in bank advance materialize, changes would have to be implemented. After 4 years of performance, the Board would expect Esso to review and, if necessary, modify the injection strategy.

With respect to completion strategy, the Board supports Esso's plan to shut off breakthrough zones by mechanical means, although the Board has some concern about how effective the attempts will be.

#### 6.3.4 Summary

The Board noted potential problems with Esso's bank size design and injection strategy. In accordance with the Board's request during the course of the hearing, Esso has agreed to submit within 4 years of commencement of the miscible flood a complete evaluation of the underlying assumptions that form the basis for Esso's continuity model, estimate of SORW, and bank size design. In addition, the Board will require Esso to include an evaluation of its injection strategy with particular attention to any problems in controlling the flood.

## 7 THE NEED FOR INFILL DRILLING

### 7.1 Views of the Applicant

In establishing its interpretation that only about 0.68 of the reservoir is floodable in a positive displacement process, Esso also generated a

relationship between interwell distance and reservoir continuity for the different stratigraphic zones in the Judy Creek BHL A Pool. Including information from infill wells drilled from 1978 to 1980, the relationship shows that well spacing would have to be less than 16 ha to significantly increase the continuous pore volume on a pool-wide basis. However, Esso agreed that the continuity versus interwell distance correlation for well spacing under 64 ha is based on relatively few data points and was not verified by production performance.

Esso stated that the decision not to pursue further infill drilling was based on the results of the 1978-1980 infill drilling program and the economic situation at that time. Esso also stated that its current decision to not undertake further infill drilling would be subject to change should further studies, production performance, or changed economics indicate that it would be justified. Esso agreed to submit to the Board a current evalution of the economic feasibility of infill drilling, and of the portions of the reservoir in which infill drilling would have the greatest effect on the miscible flood project.

Esso pointed out that it had already assumed a 0.10 primary recovery from the discontinous portion of the Judy Creek BHL A Pool, and that any infill drilling would be purely for the purpose of improving the continuity of the pool and thereby providing a greater opportunity for the injected fluid to contact a larger volume of the reservoir during miscible flood operations.

### 7.2 Views of the Interveners

Amoco questioned the validity of Esso's continuity versus interwell distance relationship. Amoco submitted that it is unrealistic to assume that continuity will only marginally improve when the interwell distance is reduced from 4000 m to 600 m. In addition, Amoco pointed out that the correlations presented in this application are quite different than those presented in a previous study by Delaney and Tsang. Amoco also stated that there are definite opportunities for infill drilling on a spot basis in the Swan Hills South miscible project, where localized areas that are not being swept can be identified.

### 7.3 Views of the Board

The Board is concerned that, if Esso's interpretation of pool continuity is correct, there may be a large volume of oil which can only be recovered through further infill drilling. The Board is also concerned that, since this infill drilling could have a significant effect on the miscible flood scheme, the decision of whether or not to infill drill must be made before the scheme is too far advanced.

It is for these reasons that the Board has requested Esso to submit, as soon as possible, a current evaluation of the economics of infill drilling and the optimum strategy under which it could be accomplished. The Board intends to pursue the matter independently of this application, so as not to delay approval of the scheme.

## 8 Decision

The Board approves the scheme of Esso Resources Canada Limited for tertiary oil recovery by applying an ethane-based miscible flood to the Judy Creek BHL A Pool. The terms and conditions of the approval will be essentially as shown in the attached Form of Approval.

DATED at Calgary, Alberta, on 6 October 1983.

G. J. DeSorcy
Vice Chairman

N. Strom
Board Member

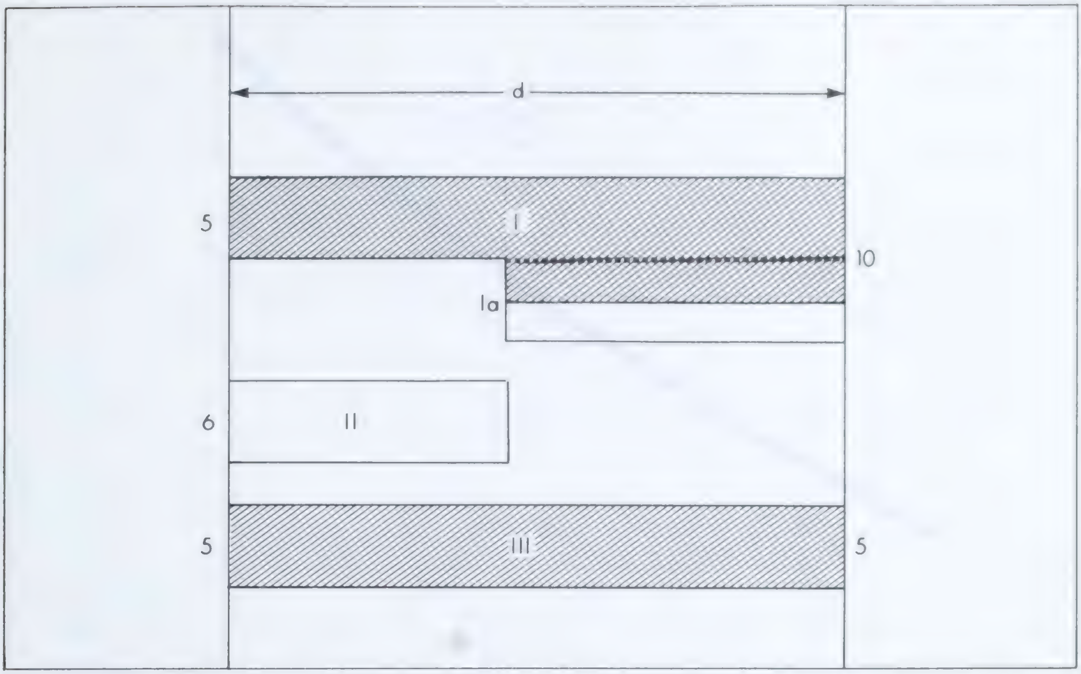
H. Antonio
Acting Board Member

TABLE 1 THOSE WHO APPEARED AT THE HEARING

| Principals and Representatives (Abbreviations used in Report) | Witnesses |
|---|---|
| Esso Resources Canada Limited (Esso)<br>R. C. Pittman<br>E. S. Denbina, P.Eng. | R.H.G. Millar, P.Eng.<br>D. G. Hay, M.Sc.<br>M. A. Konopczynski, P.Eng.<br>O. C. Biberdorf, P.Eng.<br>M.D.H. Sykes, P.Eng. |
| Amoco Canada Petroleum Company Ltd. (Amoco)<br>J. D. Griffith, P.Eng. | J. D. Griffith, P.Eng.<br>C. Patel |
| Home Oil Company Limited (Home)<br>D. G. Hart, Q.C.<br>W. Koster, P.Eng. | |
| Chevron Canada Resources Limited (Chevron)<br>D. G. Guest | |
| Dome Petroleum Limited (Dome)<br>G. S. Chwendtner<br>A. M. Danielson, P.Eng. | |
| Gulf Canada Resources Inc. (Gulf)<br>T. E. Randall, P.Eng. | |
| Mobil Oil Canada Ltd. (Mobil)<br>G. M. Bates, P.Eng. | |
| Shell Canada Resources Limited (Shell)<br>J.T.D. Courtwright<br>B. D. Weatherill, P.Eng. | |
| Energy Resources Conservation Board staff<br>G. W. Dilay, P.Eng.<br>R. J. Willard, P.Eng.<br>T. Keelan, P.Eng. | |

TABLE 2 SOLVENT INJECTION SCHEDULE

| Injection Area | Injection Period |
|---|---|
| 1 | mid 1985 to mid 1987 |
| 2 | mid 1985 to mid 1987 |
| 3 | mid 1987 to mid 1991 |
| 4 | mid 1987 to mid 1991 |
| 5 | mid 1991 to mid 1993 |
| 6 | mid 1991 to mid 1995 |
| 7 | mid 1993 to mid 1995 |




$$\text{CONTINUITY} = \frac{\text{Bed I} + (\text{Bed Ia}/2) + \text{Bed III}}{\text{Bed I} + \text{Bed Ia} + \text{Bed II} + \text{Bed III}}$$

$$= \frac{5 + 2.5 + 5}{5 + 5 + 6 + 5} = \frac{12.5}{21}$$

$$= 59.5\%$$

FIGURE 1 - CONTINUITY MODEL

JUDY CREEK BHL 'A' POOL

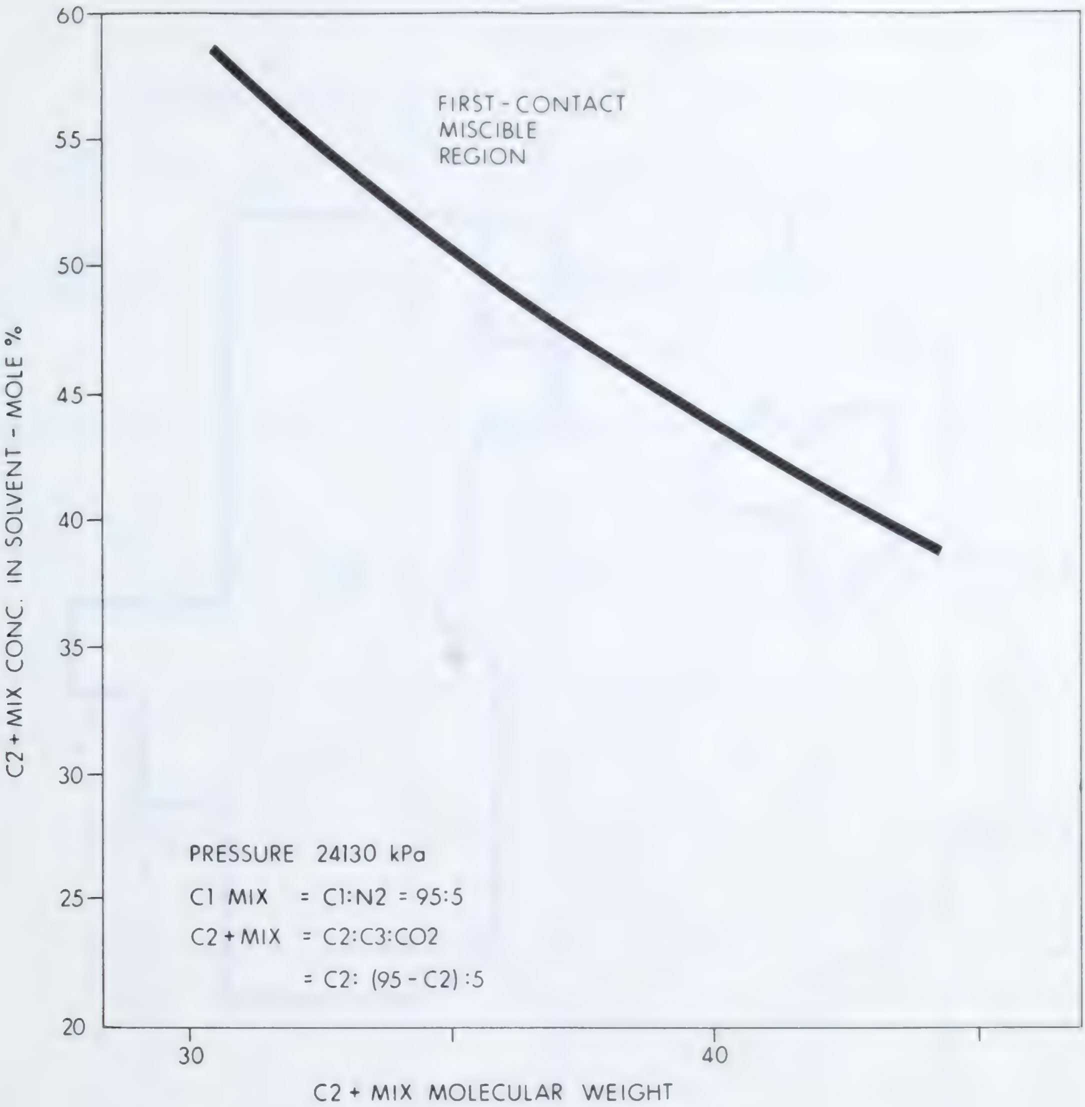



FIGURE 2 - EFFECT OF COMPOSITION ON MISCIBILITY

JUDY CREEK BHL 'A' POOL MISCIBLE PROJECT

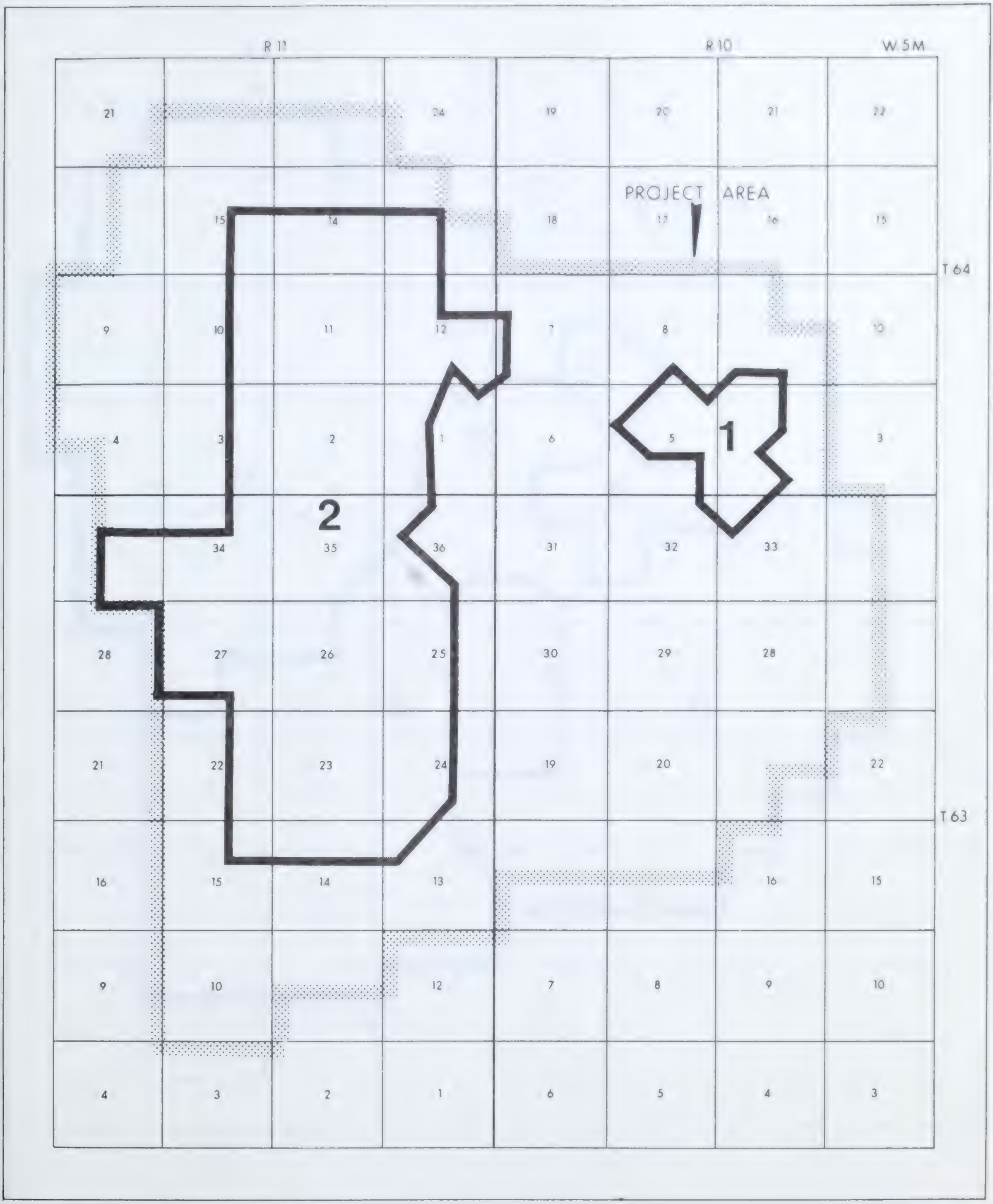



FIGURE 3 - INJECTION AREAS - EARLY PHASE

JUDY CREEK BEAVERHILL LAKE 'A' POOL

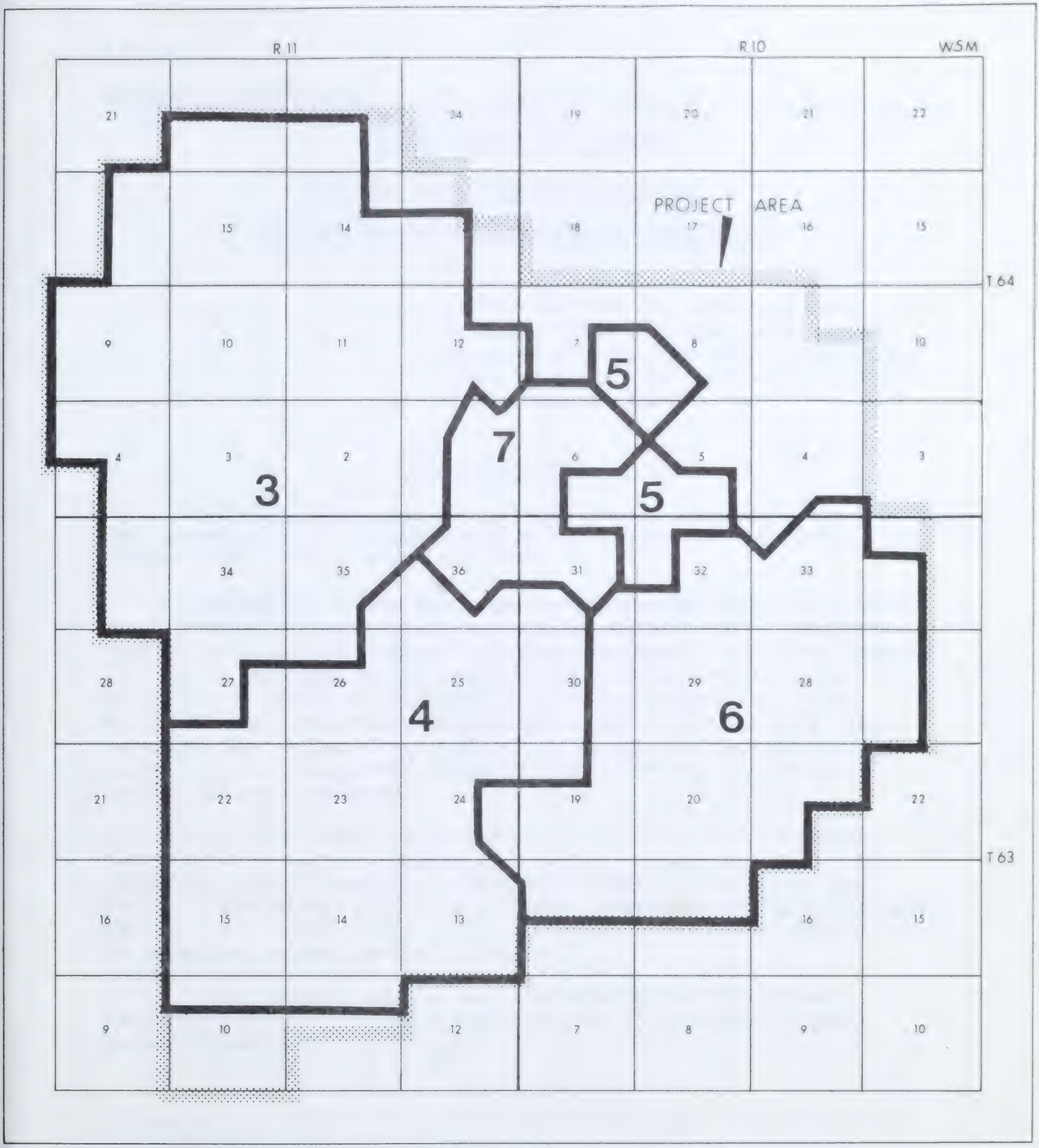



FIGURE 4 - INJECTION AREAS - LATE PHASE

JUDY CREEK BEAVERHILL LAKE 'A' POOL

APPENDIX

FORM OF APPROVAL*

THE PROVINCE OF ALBERTA

OIL AND GAS CONSERVATION ACT

ENERGY RESOURCES CONSERVATION BOARD

IN THE MATTER of a scheme of Esso Resources Canada Limited for enhanced recovery of oil by hydrocarbon solvent and water injection in part of the Judy Creek Beaverhill Lake A Pool

APPROVAL NO. ______

The Energy Resources Conservation Board, pursuant to the Oil and Gas Conservation Act, being chapter 0-5 of the Revised Statutes of Alberta, 1980, hereby orders as follows:

1. The scheme of Esso Resources Canada Limited (hereinafter called "the Operator") as such scheme is described in the letter of application dated 8 March 1983 and supporting submission dated 1 June 1983, from the Operator to the Board and in testimony given at the hearing of the application on 19 and 20 July 1983, for enhanced recovery of oil by hydrocarbon solvent and water injection in that part of the Judy Creek Beaverhill Lake A Pool shown outlined on the attached hereto, marked Appendix A to this approval, is approved, subject to the terms and conditions herein contained.

2. For the purpose of this approval, "solvent" means a suitable mixture of hydrocarbons ranging from methane to pentanes plus, but consisting largely of methane, ethane and propane. The ethane plus content of the solvent shall be of sufficient quantity to obtain first-contact miscibility with the reservoir oil as determined by the relationship shown on the attachment hereto, marked Appendix B.

3. Water, solvent and gas may be injected to the Judy Creek Beaverhill Lake A Pool through wells listed on the attachment hereto, marked Appendix C.

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* This is only a form of approval. The approval, when issued, may have minor variations from that set out herein.

4. The injection of solvent and water substantially in accordance with the scheme shall commence as detailed in the schedule set out on the attachment hereto, marked Appendix C.

5. The solvent or chase gas and water injected through the wells referred to on Appendix C hereto shall be in sufficient volumes to maintain, in the opinion of the Board, a suitable balance between solvent or chase gas and water injected into and fluids withdrawn from that part of the pool.

6. Upon commencement of solvent injection, no production may be taken from any drilling spacing unit in the Judy Creek Beaverhill Lake A Pool wherein the reservoir pressure is less than 24 130 kilopascals (gauge), unless the Board, upon application, permits otherwise.

7. The cumulative volume of solvent to be injected during the life of the scheme shall not be less than 19.6 million cubic metres at reservoir conditions and shall be distributed such that each of the 50 patterns described in the application receives a volume of solvent not less than 15 per cent of the pattern's "continuous hydrocarbon pore volume" (CHCPV).

8. The cumulative volume of chase gas to be injected during the life of the scheme shall not be less than 25.7 million cubic metres at reservoir conditions and shall be distributed such that each of the 50 patterns described in the application receives a volume of chase gas not less than 20 per cent of the pattern's CHCPV.

9. (1) Alternate volumes of water and solvent, or water and chase gas, shall be injected in accordance with the scheme, in the wells referred to on Appendix C hereto in such volumes that, at the end of each injection cycle for a given pattern, the ratio of the reservoir volume of water injected to the reservoir volume of solvent or chase gas injected during the cycle shall be 1.0.

(2) Injection to the wells referred to on Appendix C hereto shall alternate between water and solvent or chase gas at six to eight week intervals.

(3) The limits specified in clauses 9(1) and 9(2) shall not be changed without written approval from the Board.

10. Upon commencement of solvent injection into the pool, the Operator shall follow a program of sampling and analysis in accordance with the following rules:

(1) The composition of the solvent and chase gas injected into the pool shall be determined and submitted to the Board no less than once each month until such time as the Board permits, in writing, a less frequent interval.

(2) The volume and formation volume factor for chase gas and the reservoir cubic metres of solvent injected shall be provided to the Board on a monthly basis and shall contain both monthly and cumulative data.

(3) The Operator shall select at least one producing well in each pattern, and shall obtain at least one sample of the produced liquid and gas every three months. The samples are to be recombined at the producing gas-liquid ratios, and the results used to calculate the composition of the well effluent.

(4) The Operator shall determine the composition of the well effluent in the absence of solvent and chase gas injection to establish the reference level composition.

(5) When breakthrough of injected hydrocarbon solvent and/or chase gas is indicated in any of the producing wells, the Operator shall obtain and analyse at least one sample of the produced liquid and gas each month from the well at which breakthrough has occurred.

(6) Before a sample is obtained in accordance with rules 3, 4 and 5, the Operator shall produce the well until the volume of gas, oil and water production at reservoir conditions is at least three times the combined volumes of the open casing, tubing and flow line to the point of sampling.

11. (1) The Operator shall monitor the vertical distribution of injected fluids by an injection profile survey to be run at least once, for each fluid injected, in each of the wells referred to on Appendix C hereto.

(2) If an injection well is reworked, an injection profile shall immediately be taken.

12. In addition to the normal reporting requirements specified in section 12.130 of the Oil and Gas Conservation Regulations, the Operator shall report in each progress report submitted for the scheme

(a) in graphical form for each well, the producing gas-oil ratio, water-oil ratio and oil rate in cubic metres per day,

(b) instances of solvent breakthrough and the implications of the breakthrough on the efficacy of the scheme, and

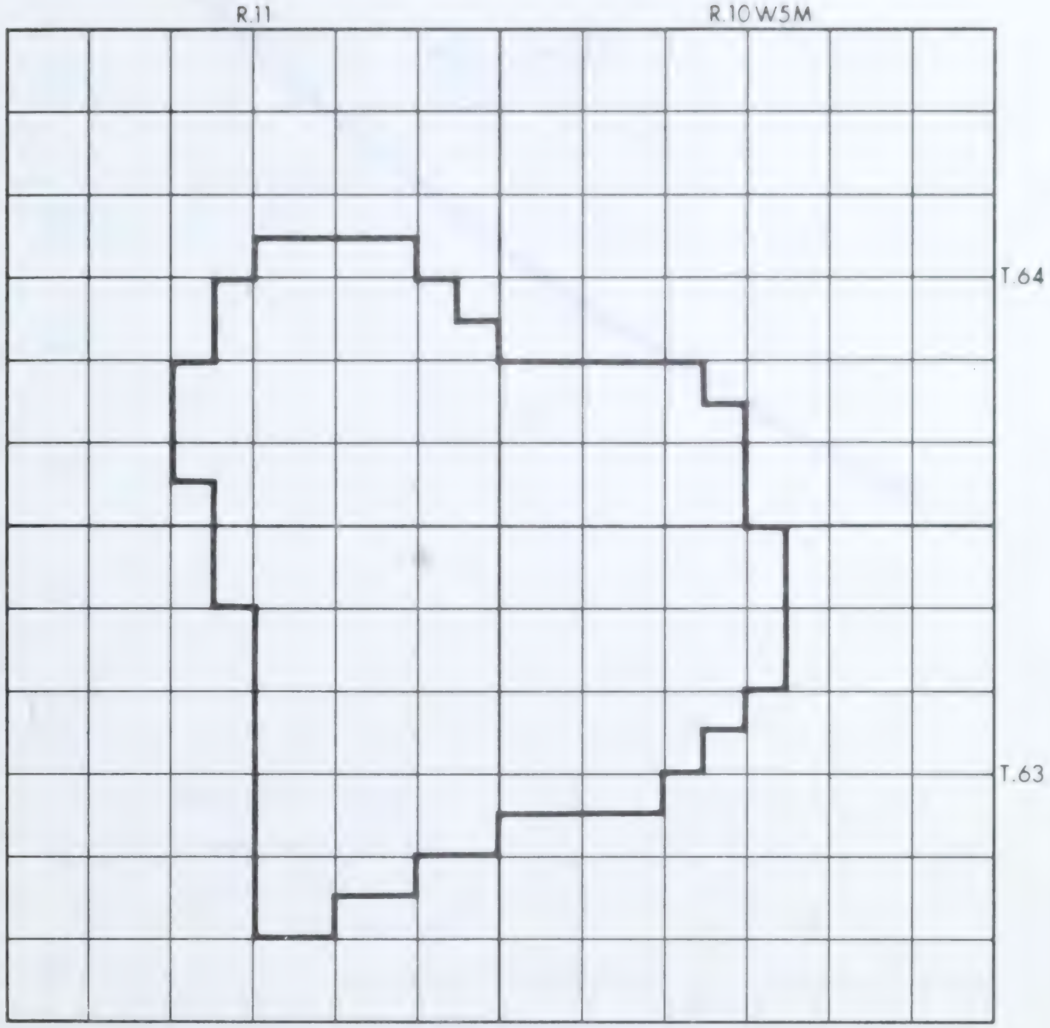
(c) the significance of the information obtained in accordance with clauses 10 and 11.

13. In addition to normal reporting requirements, the Operator shall submit it to the Board within four years after commencement of solvent injection, a report evaluating the individual patterns and overall performance of the scheme, including

(a) an evaluation of the underlying assumptions that form the basis for the Operator's continuity model, estimate of SORW and hydrocarbon bank size design,

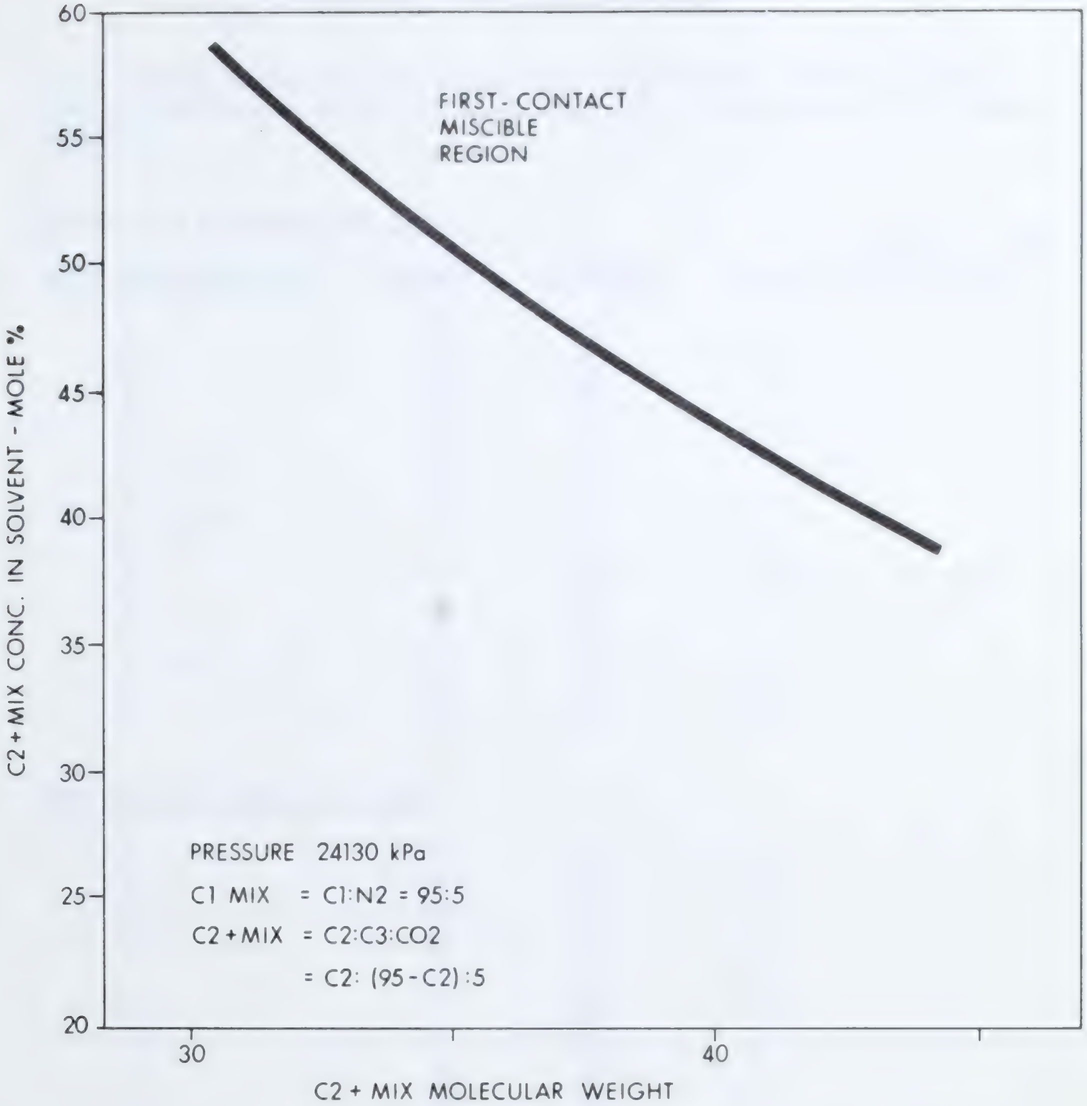
(b) an evaluation of the Operator's injection strategy with particular attention to any problems in controlling the flood, and

(c) solvent and/or chase gas breakthrough performance and the succes of any attempts to correct poor injection profiles at injectors or shut-off production of injection fluids at producers.




APPENDIX A TO APPROVAL NO.

IN THE JUDY CREEK FIELD




## APPENDIX B TO APPROVAL NO.

EFFECT OF COMPOSITION ON MISCIBILITY
JUDY CREEK BHL 'A' POOL MISCIBLE PROJECT

## APPENDIX C TO APPROVAL NO. ______

The following is the list of injection wells for the Judy Creek Beaverhill Lake A Pool miscible flood, and a schedule for the commencement of solvent injection:

Injection to commence mid 1985

(all west of the 5th Meridian)

| Legal Subdivision(s) | Section | Township | Range |
|---|---|---|---|
| 4 | 23 | 63 | 11 |
| 4 | 24 | 63 | 11 |
| 4 | 25 | 63 | 11 |
| 4 | 26 | 63 | 11 |
| 12 | 27 | 63 | 11 |
| 4 and 10 | 35 | 63 | 11 |
| 4 | 36 | 63 | 11 |
| 4 and 14 | 4 | 64 | 10 |
| 10 | 5 | 64 | 10 |
| 4 | 1 | 64 | 11 |
| 4 | 2 | 64 | 11 |
| 4 | 11 | 64 | 11 |
| 4 and 8 | 12 | 64 | 11 |
| 4 | 13 | 64 | 11 |
| 4 | 14 | 64 | 11 |

Injection to commence mid 1987

| Legal Subdivision(s) | Section | Township | Range |
|---|---|---|---|
| 4 | 30 | 63 | 10 |
| 4 | 31 | 63 | 10 |
| 10 | 13 | 63 | 11 |
| 2 | 14 | 63 | 11 |
| 2 | 15 | 63 | 11 |
| 12 | 22 | 63 | 11 |
| 4 | 3 | 64 | 11 |
| 2 | 9 | 64 | 11 |
| 4 | 10 | 64 | 11 |
| 4 | 15 | 64 | 11 |
| 2 | 22 | 64 | 11 |

Injection to commence mid 1991

| Legal Subdivision(s) | Section | Township | Range | (all west of the 5th Meridian) |
|---|---|---|---|---|
| 12 | 17 | 63 | 10 | |
| 4 | 19 | 63 | 10 | |
| 4 | 20 | 63 | 10 | |
| 4 | 21 | 63 | 10 | |
| 4 and 12 | 27 | 63 | 10 | |
| 4 | 28 | 63 | 10 | |
| 6 | 29 | 63 | 10 | |
| 4,10 and 12 | 32 | 63 | 10 | |
| 4 and 10 | 33 | 63 | 10 | |
| 2 and 4 | 5 | 64 | 10 | |
| 2 | 6 | 64 | 10 | |
| 4 | 8 | 64 | 10 | |

Injection to commence mid 1993

| | | | |
|---|---|---|---|
| 10 and 12 | 31 | 63 | 10 |
| 10 | 36 | 63 | 11 |
| 4,10 and 12 | 6 | 64 | 10 |
| 2 and 10 | 1 | 64 | 11 |

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta



PETRO-CANADA INC.
GAS PROCESSING PLANT
BRAZEAU RIVER FIELD

Decision D 83-20
Application 830041

# 1 THE APPLICATION AND HEARING

## 1.1 The Application

Petro-Canada Inc. (Petro-Canada) applied pursuant to section 26 of the Oil and Gas Conservation Act for approval to construct a plant proposed to be located in legal subdivision 4 of section 31, township 48, range 12, west of the 5th meridian (4-31), to process sour gas from the Brazeau River Field. The plant would process 706 thousand cubic metres per day ($10^3$ $m^3$/d) of raw gas from which 525 x $10^3$ $m^3$ of residue gas, 220 $m^3$ of natural gas liquids (NGL), 630 $m^3$ of liquid condensate, and 78.4 tonnes of sulphur would be recovered. The proposed plant would recover 98 per cent of the sulphur contained in the raw gas inlet stream to the plant. A maximum of 3.2 tonnes per day (t/d) of sulphur dioxide ($SO_2$) would be emitted to the atmosphere through an incinerator stack 45.7 metres in height.

Residue gas would be injected into the Brazeau River Nisku M Pool (M Pool) at the well in 7-20-48-13 W5M (7-20) in accordance with Board Approval No. 3834, and at the well in 5-8-48-13 W5M (5-8), subject to Board approval of a proposed gas cycling scheme for the Brazeau River Nisku F Pool (F Pool). Petro-Canada also proposed to inject excess residue gas into miscible flood schemes operating in the Brazeau River Nisku A, D, and E Pools in accordance with Board Approvals No. 3062, 3350, and 3174, respectively. Raw gas would be produced from the 6-20-48-13 W5M (6-20) and 4-8-48-13 W5M (4-8) wells in the M and F pool gas cycling schemes, and from five Nisku Formation Carbonate Bank wells located at 2-19-48-12 W5M (2-19), 3-20-48-12 W5M (3-20), 2-11-48-13 W5M (2-11), 2-12-48-12 W5M (2-12), and 7-10-48-12 W5M (7-10).

The figure shows the proposed plant and well locations, pipeline routes, and the Critical Wildlife Zone and Wildlife Key Area along the Pembina River and Dismal Creek.

## 1.2 The Hearing

The application was considered at a public hearing in Drayton Valley, Alberta, on 19 and 20 July 1983, with V. E. Bohme, P.Eng., C. J. Goodman, P.Eng., and J. A. Bray, P.Eng. (acting Board Member), sitting.

The appendix lists the participants at the hearing.

## 2 ISSUES

Having considered the evidence, the Board believes that the issues raised by the application are:

- need for processing capacity in the area,
- economic, orderly, and efficient development of the area, and
- related environmental matters.

## 3 NEED FOR PROCESSING CAPACITY IN THE AREA

### 3.1 Applicant's Views

Petro-Canada stated that it and its partners had drilled numerous wells in the area and had, in its view, proven sufficient reserves to justify the construction of a gas processing plant capable of processing 706 x $10^3$ $m^3$/d of raw gas. The applicant contended that its plant was needed to cycle gas from the F and M pools, to allow production from the Carbonate Bank area in order to delineate those reserves and to supply residue gas to miscible flood oil recovery schemes in the area. Petro-Canada said that production from the 2-11, 2-12, 2-19, 3-20, and 7-10 wells would help delineate the boundary of the Carbonate Bank and allow for proper evaluation and planning of future expansion.

Petro-Canada stated that processing plants in the area did not have sufficient capacity to process all of its gas and emphasized that it wanted to process its own gas for economic and operating flexibility reasons. It needed a plant to facilitate gas cycling and recover F and M pool hydrocarbon liquids for which it has a market. Plant start-up would be near the end of 1984.

### 3.2 Interveners' Views

Hudson's Bay Oil and Gas Company Limited (HBOG) did not support or oppose the Petro-Canada plant, but stated that by extending its recently approved gathering system and by expanding its gas plant under construction at 6-10-47-14 W5M (6-10 plant), it could accommodate the area's reserves. However, HBOG stated that it did not propose that any Petro-Canada wells other than those in the F Pool be connected to its gathering system at this time. HBOG stated that upon completion of its plant in May 1984, it would be able to process all F Pool production by reducing production from some of its other wells and without expansion of the plant.

HBOG stated that producing its 7-34-47-12 W5M well should help delineate part of the Carbonate Bank. It also agreed with Petro-Canada that producing the 2-11, 2-12, 2-19, 3-20, and 7-10 wells would provide more information and not affect HBOG plans.

The remaining interveners did not question the need for additional processing in the area.

### 3.3 Board's Views

The Board accepts that Petro-Canada has a right to produce its reserves and notes its plans to use residue gas for cycling and for miscible flood purposes, as well as its markets for hydrocarbon liquids. The Board therefore believes that processing capacity is required and accepts the need for the Petro-Canada plant, provided it represents economic, orderly, efficient development and provided the related environmental impacts are acceptable.

## 4 ECONOMIC, ORDERLY, AND EFFICIENT DEVELOPMENT OF THE AREA

To evaluate whether the Petro-Canada proposal represents economic, orderly, and efficient development of the area, the Board considered the relative advantages and disadvantages of processing the area's gas reserves at a single location (such as at an expanded HBOG plant) or at two locations (if the Petro-Canada plant were approved). In this regard, the Board considered plant locations, utilization of existing facilities, costs, impacts of associated pipelines, and other environmental considerations such as sulphur recovery efficiencies. It also reviewed the development plans for the F Pool having regard for conservation.

### 4.1 One Plant Site Versus Two Plant Sites

#### 4.1.1 Applicant's Views

Petro-Canada noted that it had evaluated five alternative plant sites prior to selecting the 4-31 site, and stated that the 4-31 site would be about 3 kilometres (km) outside the Critical Wildlife Zone, centrally located to its wells (within a 10-km radius) and, because the proposed plant would be adjacent to Petro-Canada's existing 4-31 battery, it would not produce the environmental impacts of a new plant site.

Petro-Canada said that sigificant savings could be realized by using the 4-31 site because many existing facilities could be utilized. It cited existing injection compressors, power lines, access roads for liquid sulphur transport, office buildings, warehouses, and liquid

storage facilities. The applicant stated that if its gas were processed at an expanded HBOG plant, a pipeline from the HBOG 6-10 plant to the 4-31 site would be needed to transport residue gas to the existing miscible flood schemes.

Petro-Canada said that while it had been offered equity participation in an expanded HBOG plant, it believed it could more economically process its gas through a plant of its own. The applicant claimed HBOG had been unwilling to finalize equity participation costs and therefore Petro-Canada had estimated those costs itself. It estimated an HBOG plant expansion at $47.3 million in comparison to the cost of the 4-31 plant which would be $43.2 million.

Petro-Canada contended that its gathering system pipelines, in conjunction with the necessary NGL and condensate pipelines needed to service its 4-31 site, resulted in less "total product movement" than that of the HBOG alternative. Regarding the necessary pipelines to gather the gas, Petro-Canada said it was preparing pipeline applications for approval to connect its wells to the 4-31 plant, to return residue gas for re-injection, and to supply fuel gas for well site facilities. It had selected its routes so that the majority of its pipelines would be north of the Pembina River, still inside the Critical Wildlife Zone but outside the area between the Pembina River and Dismal Creek. It stated these re-routings were to reduce the concerns of the Department of Energy and Natural Resources about extensive linear developments in that area. Although it had not yet applied for permits to construct the pipelines, it was confident that environmentally acceptable pipelines could be built.

Petro-Canada stated that its pipeline from the M Pool to the F Pool would result in less impact to the Critical Wildlife Zone and the Wildlife Key Area because the majority of its pipeline would be between those areas while the HBOG pipeline from 9-1-48-14 W5M (9-1) to 8-7-48-13 W5M (8-7) would be entirely within the Wildlife Key Area.

Petro-Canada also stated that some environmental benefits might accrue from two separate plants since the proposed sulphur recovery efficiencies for both the HBOG and Petro-Canada plants are the same and the total emissions from the two plants would undergo wider dispersion from two emission points. It also noted that its plant would be located on an elevated ridge.

4.1.2 Interveners' Views

HBOG stated that its 6-10 gas plant was proposed for start-up in May 1984 and that its gathering system would then be operational.

HBOG believed that the infrastructure benefits cited by Petro-Canada for its 4-31 site would also be available at the HBOG 6-10 plant when completed. It said that the 6-10 plant would also have the necessary access roads, power, sufficient compression for re-injection, offices, and warehouses.

HBOG stated that, contrary to Petro-Canada's estimated costs for expansion of the HBOG plant, its facilities could be expanded and modified to process the subject gas for about $36 million. It claimed that the Petro-Canada estimate assumed a new grass roots plant would be constructed and did not recognize the lower costs that would be achieved by utilizing common facilities.

HBOG stated that, while its pipeline system had capacity to handle production from Petro-Canada's 2-11, 2-12, 2-19, 3-20, and 7-10 wells, it proposed to tie-in only the F Pool to its plant at this time. HBOG stated that although its plant would require expansion to process more than F Pool gas, it had been designed to be expanded easily and could be enlarged by early to mid 1985, if necessary, to process all the gas in the area.

HBOG disagreed with Petro-Canada's position that processing all the gas from the area at the HBOG plant would result in "extra miles of product movement". It claimed that condensate sales at its plant gate obviated including the condensate sales pipeline in any product movement evaluation. Similarly, HBOG contended that, based on the insignificant incremental costs of transporting NGL to its final delivery point, the extra NGL sales pipeline should not be included. It noted that in comparing expanding the HBOG plant to building a new Petro-Canada plant, those pipelines to its plant would be required in any event. HBOG believed that extending its gathering system to the Petro-Canada wells and processing the gas at the 6-10 plant location resulted in more economic, orderly, and efficient development.

HBOG stated that its proposed pipeline from 9-1 to 8-7 to gather F Pool production would be shorter than the tentative Petro-Canada pipeline from 7-20 to 5-8. HBOG stated that this would minimize environmental impacts in the area, although it said that if the Petro-Canada scheme was approved, then it would prefer pipelines from the F Pool to both plants as opposed to the Petro-Canada plant only. HBOG also indicated that it could easily extend its re-injection pipeline from 9-1 to the F Pool.

The Pembina Area Sour Gas Exposures Committee (PASGEC) said it wanted the lowest possible sulphur emissions from any gas plants in the area. It also believed that pipelines from both the HBOG and Petro-Canada plants would result in duplication of facilities.

The Crown, on behalf of the Department of Energy and Natural Resources, questioned Petro-Canada about the lengths of its proposed pipelines within the Critical Wildlife Zone and argued that the length as well as the number of river crossings should be minimized if possible.

#### 4.1.3 Board's Views

The Board believes that the proposed Petro-Canada plant and the HBOG plant under construction are essentially two different schemes notwithstanding the competition for the F Pool reserves. The Board accepts Petro-Canada's reasons for selecting the 4-31 site and agrees that the site may provide some advantages in terms of supplying gas to miscible flood schemes and in making use of the existing 4-31 infrastructure.

The economic information provided was not sufficiently detailed to permit an accurate comparison of the costs of constructing a new plant with that of expanding the HBOG plant; however, the Board believes that the costs for an expansion at the HBOG 6-10 plant would be similar to the Petro-Canada plant cost.

The Board has considered the tentative pipeline routings to the Petro-Canada plant and believes Petro-Canada should be able to address environmental concerns, and that the routes appear to be reasonably efficient for development of Petro-Canada's reserves and for delivery of plant products. The Board sees little environmental difference between the two pipelines to the F Pool proposed at the hearing, because both the Petro-Canada and HBOG gathering systems between the 6-20, 8-7, and 9-1 wells could follow the same route as the Amoco NGL pipeline required to service the HBOG 6-10 plant. The Board notes that the Crown expressed a desire for environmentally efficient development in the area but did not object to the Petro-Canada pipeline routing.

The proposed sulphur recovery efficiencies for the two plants are the same and the Board accepts the premise that there would be a wider dispersion of the sulphur emitted from two sources than from a single source. However, it does not regard this as a significant change to the environmental impact.

The Board is satisfied that the proposed Petro-Canada plant would be consistent with economic, orderly, and efficient development of the area.

### 4.2 F Pool Development Plans

#### 4.2.1 Applicant's Views

Petro-Canada stated that it had filed an application with the Board for a gas cycling scheme in the F Pool which proposes about one year of primary depletion until the reservoir dewpoint is reached, followed

by approximately 11 years of cycling at an optimum rate of 140 x $10^3$ $m^3/d$. Petro-Canada suggested that, compared to the HBOG plant, processing the F Pool gas at its plant would result in the recovery of about 10 per cent more liquids. Additionally, Petro-Canada discounted any economic advantage from early processing of its share of F Pool production at the HBOG site because a pipeline from the HBOG plant to the miscible flood schemes would be required. It said it would proceed with its own plant even if the F Pool was not included in its approval.

#### 4.2.2 Interveners' Views

HBOG said it was the largest individual mineral owner in the F Pool and stated it wants to process its gas at its plant because the F Pool production would provide a more economic source of supply than other wells in the area (not currently proposed for tie-in). HBOG supported competitive primary depletion of the F Pool and said that it was prepared to accommodate all F Pool gas by backing out some of its other production. HBOG contended that the optimum cycling rate was 280 x $10^3$ $m^3/d$, about twice Petro-Canada's estimate, and disagreed with Petro-Canada's claim of increased liquid recovery if F Pool gas were processed by the Petro-Canada scheme. HBOG argued that the Board should approve its deferred pipeline application between the 9-1 and 8-7 well locations.

#### 4.2.3 Board's Views

After considering the information available, and noting not only the lack of detail, but also the conflicting evidence presented at the hearing regarding conservation and optimum cycling rates for the F Pool, the Board has decided to defer inclusion of the F Pool in Petro-Canada's proposed processing scheme until it has fully considered the cycling scheme application. Similarly, the Board will not rule on HBOG's pipeline application between the 9-1 and 8-7 locations until that time.

## 5 RELATED ENVIRONMENTAL MATTERS

### 5.1 Applicant's Views

Petro-Canada stated that its proposed plant would employ the best practical technology to achieve sulphur recovery higher than the 96.5 per cent required under the Board's guidelines. It planned to achieve 98 per cent sulphur recovery and would install equipment designed to achieve 99 per cent recovery on an annual basis to ensure it could meet the 98 per cent target. The applicant stated that its facility was designed to emit 1.6 t/d of sulphur, but it expected the emissions

would actually be about one t/d. Petro-Canada stated that because of the 98 per cent sulphur recovery proposed, the $SO_2$ emissions would be the lowest in the province relative to the plant size. It further stated that when the plant was operating normally it would achieve a sulphur recovery somewhat higher than 98 per cent. Petro-Canada noted that it chose a higher recovery at additional cost because of its regard for the environment, but maintained that incremental sulphur recovery costs must be limited to ensure project viability.

## 5.2 Interveners' Views

PASGEC stated that best available technology should be employed in the Petro-Canada plant. It contended that the best available technology would cost in the order of an additional \$3 to \$4 million to render the plant almost free of sulphur emissions and claimed this represented a small increment over the total cost of developing the gas reserves dedicated to the proposed plant. PASGEC contended that area residents have been sensitized to hydrogen sulphide and $SO_2$ emissions because of exposure to those gases during the Amoco Lodgepole well blowout.

## 5.3 Board's Views

The Board considered the concerns raised by PASGEC regarding the possible sensitization of area residents which might create problems that could be exacerbated by the operation of the proposed plant, but notes that PASGEC did not present evidence to substantiate its sensitization premise. Alberta air quality standards are taken from those established by Environment Canada and are the most stringent of those specified by that agency. No evidence was presented by the interveners to suggest or demonstrate that the standard is inadequate nor that the predicted ground level concentrations would cause human health problems. In fact, predicted ground level concentrations of $SO_2$ in the vicinity of Cynthia and Lodgepole resulting from the operation of small plants in the area were estimated by Petro-Canada to be less than 1 parts per billion (ppb) on an annual basis. This is about 1/10 the limit of 11 ppb $SO_2$ permitted by the standards. The Board thus has no reason to conclude that the proposed plant will have a negative impact on human health.

# 6 SUMMARY

The Board concludes that additional gas processing capacity is needed to process gas reserves in the Brazeau River area and that the proposed Petro-Canada scheme provides for economic, orderly, and efficient development of the area and is environmentally acceptable.

Concerning development of the F Pool, the Board strongly believes that a voluntarily negotiated unit agreement among the mineral owners would provide for optimum development and it is not anxious to infringe on such negotiations. For that reason, and because the evidence presented at the hearing regarding the operation of the pool was cursory and conflicting, the Board believes it should defer its decision to include the F Pool in Petro-Canada's gas processing scheme until the gas cycling scheme has been considered.

## 7 DECISION

The Board is prepared to approve Application 830041 of Petro-Canada Inc., subject to the following:

- Inclusion of the Brazeau River Nisku F Pool in the gas processing scheme is deferred until the Board considers the gas cycling scheme for that pool.

- Approval is received from the Minister of the Environment respecting matters affecting the environment.

DATED at Calgary, Alberta on 19 August 1983.

ENERGY RESOURCES CONSERVATION BOARD

V. E. Bohme
Board Member

C. J. Goodman

C. J. Goodman
Board Member

J. A. Bray
Acting Board Member

APPENDIX

THOSE WHO APPEARED AT THE HEARING

| Principals and Representatives (Abbreviations used in Report) | Witnesses |
|---|---|
| Petro-Canada Inc. (Petro-Canada) | A. Richards |
| | M. Davies |
| D. O. Sabey, Q.C. | Dr. L. Lewis |
| B. K. O'Ferrall | F. J. Bagley, P.Eng. |
| W. Gallagher | G. Reitzel, P.Eng. |
| | S. Patel, P.Eng. |
| | P. H. Verity, P.Eng. |
| Hudson's Bay Oil and Gas Company Limited (HBOG) | Dr. G. Besserer, P.Eng. |
| | E. J. Muchowski, P.Eng. |
| A. L. McLarty | J. R. Moore, P.Eng. |
| R. A. Neufeld | W. Leithead, P.Eng. |
| | G. C. Mott |
| Texaco Canada Resources Ltd. (Texaco) | |
| R. Blumell | |
| Amoco Canada Petroleum Company Ltd. (Amoco) | |
| A. G. Kruse | |
| Pete Calvert Road Maintenance | P. Calvert |
| P. Calvert | |
| Wild Card Enterprises Ltd. | B. T. Clemmer |
| B. T. Clemmer | |
| D. V. Meter Ltd. | G. S. Lorenz |
| G. S. Lorenz | |
| Town of Drayton Valley | J. Wolf |
| J. Wolf | |
| Pembina Area Sour Gas Exposures Committee (PASGEC) | R. MacIntosh |
| J. C. Prowse, Q.C. | O. Baker |
| D. P. Mallon | C. Whitelock |

THOSE WHO APPEARED AT THE HEARING (cont'd)

| Principals and Representatives (Abbreviations used in Report) | Witnesses |
|---|---|
| Her Majesty the Queen in Right of Alberta (the Crown)<br>G. F. Roy | |
| Energy Resources Conservation Board staff<br>D. A. Holgate<br>E. P. Moeller, C.E.T.<br>M. A. Francis, C.E.T.<br>H. W. Knox, P.Eng. | |

Gooding and Matt Construction Ltd., Braidnor Construction Ltd., Gillis Oilfield Construction Ltd., Jer-Ann Trucking Ltd., Town of Edson, and USS Oilwell Supply Co. Ltd., filed submissions but did not appear at the hearing.

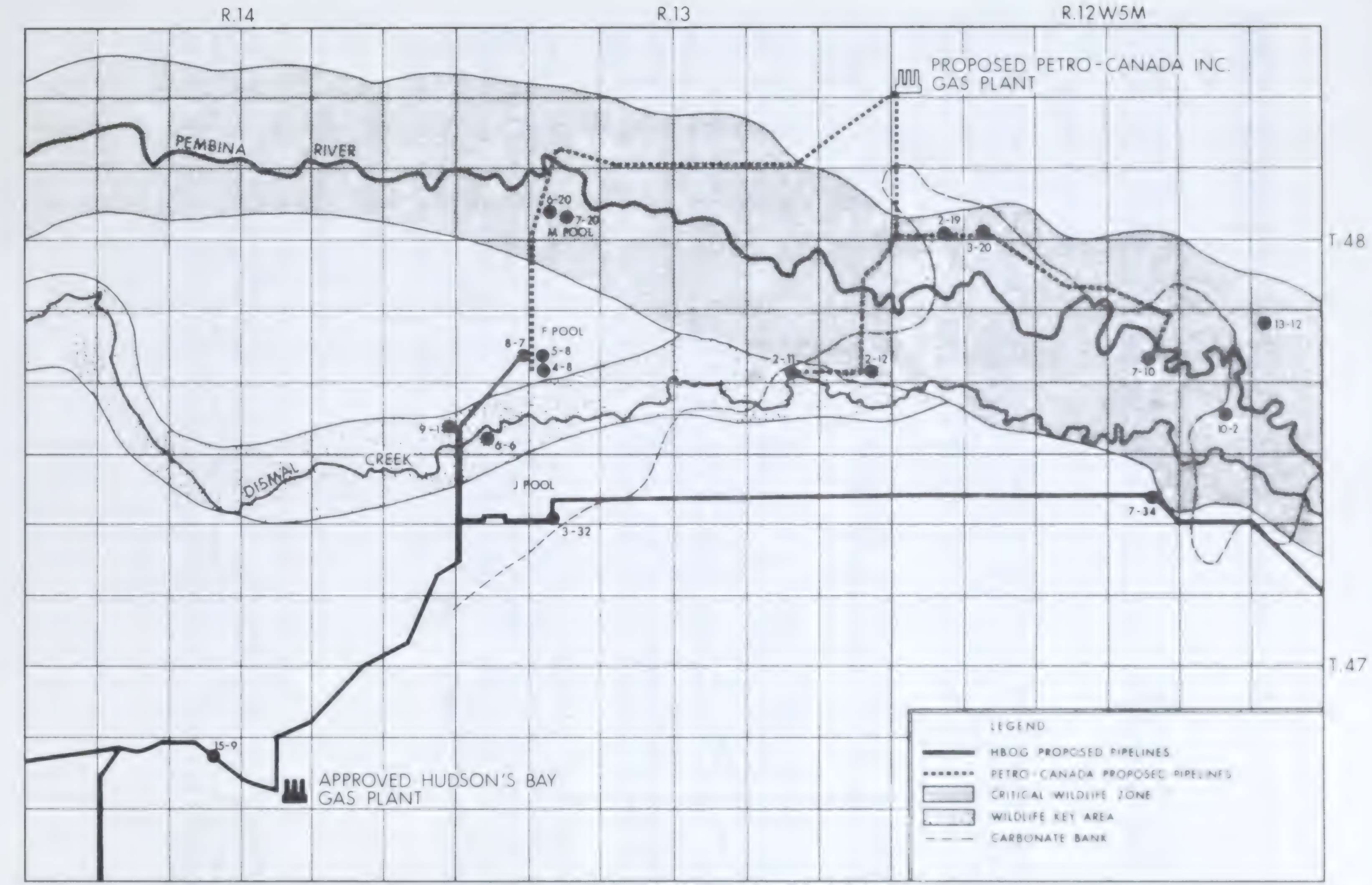



FIGURE PETRO-CANADA – BRAZEAU RIVER GAS PLANT LOCATION AND AREA

ERCB

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

ESSO RESOURCES CANADA LIMITED
APPLICATION FOR PHASED DEVELOPMENT
OF THE COLD LAKE OIL SANDS PROJECT

Decision D 83-21
Application 830620

## 1 INTRODUCTION

In late 1978 and early 1979, the Board heard an application by Esso Resources Canada Limited (Esso) for approval of a scheme to produce and upgrade crude bitumen from the Cold Lake oil sands deposit. In October 1980, the Board heard an application to amend the scheme to use natural gas rather than coal as a make-up fuel.

Both applications were considered by a panel made up of G. J. DeSorcy, P.Eng., Dr. N. Berkowitz, P.Eng., V. E. Bohme, P.Eng., W. S. Solodzuk, P.Eng., and W. D. Isbister, Esq.

Reports on the applications and hearings were contained in ERCB Report 79-E and ERCB Decision 81-C issued respectively in October 1979 and February 1981. The Board indicated that it was prepared to approve the applied-for mega-project, subject to a number of conditions set out in the decision reports and to receipt of authorization from the Lieutenant Governor in Council. Each decision report contained a form of approval the Board was prepared to issue, but Esso suspended work on the project because of changed economic conditions and neither the requested authorization of the Lieutenant Governor in Council nor the approval was issued.

Esso applied pursuant to section 42 of the Energy Resources Conservation Act in June 1983 for a variation to the approval the Board had indicated it was prepared to issue, which would allow the original Cold Lake project to proceed on a phased basis. The application was heard by the Board beginning 8 August 1983 in Grand Centre with G. J. DeSorcy, P.Eng., Dr. N. Berkowitz, P.Eng., and V. E. Bohme, P.Eng., sitting. Those who appeared at the hearing are listed in the attached table.

## 2 APPLICATION

### 2.1 The Earlier Project

The earlier project was for approval to produce 25 400 cubic metres per day ($m^3/d$) - 160 000 barrels per day (bbl/d) - of bitumen from the Clearwater Formation underlying the area marked as 1 in the attached figure. Recovery was to be by an in situ steam stimulation process which would involve cyclical periods of injecting steam into the reservoir and producing water and bitumen. The recovery forecast by Esso was some 20 per cent of the bitumen in place.

Production and injection would have been through some 10 000 wells directionally drilled in 20-well clusters from surface drilling pads. The bottom-hole spacing would be a rectangular grid with a well every 1.62 hectares (4 acres). Up to 2000 wells would have operated at any time.

Each drill site was to become a satellite at which pumping units for each well and separation and measurement equipment would exist. Produced fluids would then be transported to a central plant for further treatment prior to delivery to upgrading facilities. Flow lines for steam and produced bitumen were to be installed above ground.

The earlier project also involved the upgrading of bitumen by a Flexicoking process and subsequent hydrotreating which would have yielded some 22 300 $m^3/d$ (140 000 bbl/d) of synthetic crude oil.

Natural gas was to be used as make-up fuel, and the fresh make-up water would have been piped to the area from the North Saskatchewan River. Some 99.8 per cent of the sulphur released from the bitumen would have been converted to elemental sulphur.

The earlier project was to involve extensive environmental controls to minimize impacts on land, air, and water. Construction was to commence in 1980, with plant start-up planned for about 1986.

The construction labour force for the earlier project would have peaked at some 9970 persons and the project would have offered employment for some 3000 people per year over the life of the project.

## 2.2 The Phased Project

Esso has now applied for approval of a phased concept for the Cold Lake project rather than its original mega-project scheme. It indicated that current economic and business conditions would not support a mega-project approach to oil sands development and that a step-by-step development was required. As an initial step, the proponent intends to proceed with Phases I and II.

Esso proposed to proceed with the project in stages, each involving 1500 $m^3/d$ (9450 bbl/d) of bitumen production. The current application for approval of Phases I and II would allow production of a total of 3000 $m^3/d$ (18 900 bbl/d) of bitumen. Esso expected that Phases III through VI, producing an additional 6000 $m^3/d$ (37 800 bbl/d) of bitumen, would be started by 1990.

Phases I and II would occur in the area marked as 2 in the attached figure. The basic recovery process would be steam stimulation as originally proposed, although conversion to some other recovery method would be possible in future. The expected recovery is 20 per cent which Esso considers reasonable in view of the fact that the project area has been selected on the basis of quality of the reservoir and geotechnical conditions.

Some 756 000 $m^3/d$ of natural gas would be required as fuel, of which some 660 000 $m^3/d$ would be make-up fuel purchased from the local supply system.

The overall energy efficiency of the project is such that for each unit of energy input, 4.4 units of energy are marketed as bitumen.

The field producing facilities would be similar to those proposed in the original mega-project, but much smaller. There would be a total of 800 wells with up to 220 in operation at any time. The wells would be drilled in clusters of 20 which would be connected to producing satellites. Production would then be moved through an above-ground gathering system to a central fieldgate unit for further processing. The steam distribution system would also be above ground.

At the fieldgate, free water and gas would be removed from the bitumen. It would then be diluted with gas condensate (pentanes plus) and further processed to remove basic sediments and water. Additional diluent would be added as necessary to control the fluid viscosity for pipelining purposes as the bitumen would not be upgraded prior to marketing.

Esso submitted that upgrading of bitumen to synthetic crude, as proposed in the earlier application, would not take place in conjunction with Phases I and II, but would be deferred until economic and business opportunities provide a favourable climate for upgrading.

The diluted bitumen would be shipped through the Alberta Oil Sands Pipeline to the Edmonton area for eventual marketing in the northern tier of the United States. Some 1500 $m^3/d$ (9450 bbl/d) of gas condensate would be required as diluent for Phases I and II.

Make-up water for Phases I and II would be some 3275 $m^3/d$ (20 600 bbl/d). Esso said that provision of water for these phases would be in accordance with a regional water management plan. Under that plan, make-up water for the first two phases would come from Cold Lake. Esso stated that it had the necessary water withdrawal licence from Alberta Environment.

Some 5 sections of land, compared to 55 in the earlier application, would be affected and a development and reclamation plan is being prepared. About 1.5 tonnes per day of sulphur dioxide ($SO_2$) would be emitted to the atmosphere. Waste water would be disposed of by injection into the Cambrian Formation.

The construction work force would peak at about 700, and 90 workers would be required during the operations phase. Esso proposed to commence construction before the end of 1983, and expects initial production in 1985.

## 3 PRELIMINARY MATTERS

There is one matter raised at the hearing with which the Board believes it necessary to deal with at the outset of this report.

The Tribal Chiefs asked the Board to delay its recommendations to the Cabinet for 60-90 days so that the Indian people of the area could negotiate the following matters with Esso:

(a) on behalf of the Cold Lake Band, the development of its resources;

(b) the contracts for operation of a drilling company by the Indian people;

(c) obtaining from Esso a contract or contracts for services such as land clearing contracts;

(d) such other agreements as will ensure for the Indian people the fullest use of their goods and services in the project.

Esso stated that it was prepared to discuss the matters with the Indian people but opposed a deferral of the Board's decision while those discussions were taking place. It also stated that with the turndown in oilfield drilling, formation of a drilling company by the Indian people at this time would appear ill-advised.

The Board believes that if the proposed project is approved and proceeds, certain of the matters raised by the Tribal Chiefs should be discussed between Esso and the Indian people. It further believes that such discussions should be ongoing, and that meaningful communication should continue for so long as Esso is working in the area. The Board accepts Esso's undertaking to communicate with the Indian people and sees no advantage in deferring its consideration of the application pending the outcome of discussions.

## 4 INTERVENTIONS

None of the interveners were opposed to the project.

The local Chamber of Commerce groups and Lakeland College expressed support for the Cold Lake project and agreement with the phasing concept.

The Cold Lake Band and Tribal Chiefs also supported the phased project in principle, but requested consideration of conditions related to training and business and employment opportunities for Native people. The Cold Lake Band further requested conditions for environmental monitoring and follow-up handling of environmental problems by government agencies.

The Trappers Association expressed concern over compensation for trap lines on and adjacent to the development area as they may be affected by the proposed development.

## 5 ISSUES TO BE CONSIDERED

The Board deems the subject application to be a modification of a proposal which it had previously considered in detail and which it was prepared to approve as being in the Alberta public interest. It will therefore be

assessed in light of the Board's findings which have been reviewed only insofar as required by new evidence.

The Board also believes that it should consider the subject application, not only in terms of the suitability or otherwise of the concept of phasing, but also with respect to the proposal to proceed specifically with Phases I and II at this time.

With this in mind, the Board considered the following issues in some detail, all of which would involve substantial modifications of the originally planned project.

- The need for the project, the concept of a phased project including deferral of bitumen upgrading, and the resulting influence on the Board's earlier views respecting environmental and social impact, and the benefits and costs of the project.

- The availability of the condensate diluent, the impact on Alberta users of that diluent, and the marketing of the diluted bitumen.

- The use of Cold Lake for make-up water for Phases I and II of the project.

In addition to these major matters, the Board briefly reviewed the following aspects which have changed only in relatively minor details, other than in size or timing.

- The technical aspects of the in situ recovery process and its adequacy.

- Well drilling and completions.

- Surface production facilities including new plant site.

- Subsurface water disposal.

- Make-up fuel.

- Exclusion of experimental project areas.

Additionally, there was considerable discussion at the hearing respecting:

- Training for Native people.

- Business and employment opportunities for Native people.

Although these matters are beyond its jurisdiction, the Board intends to report the evidence adduced at the hearing by the Native groups and present conclusions and recommendations for consideration by the Lieutenant Governor in Council.

# 6 NEED FOR THE PROJECT, CONCEPT OF A PHASED PROJECT INCLUDING DEFERRAL OF BITUMEN UPGRADING, AND RESULTING INFLUENCE ON THE BOARD'S EARLIER VIEWS RESPECTING ENVIRONMENTAL AND SOCIAL IMPACT AND BENEFITS AND COSTS OF THE PROJECT

## 6.1 Need for the Project

The applicant's position on the need for the project remains as at the previous hearings when it indicated that oil from the oil sands is necessary if Canada is to approach self-sufficiency in oil supply. It acknowledged that although the production would be marketed in the U.S., it would become a source of supply to Canada when upgrading facilities are installed at a later date.

The interveners who supported the project also noted that implementation would have a positive effect on the local economy.

The Board is satisfied that the proposed project would have a favourable economic impact on Alberta and Canada at a time when the economy is seriously lagging. It would allow advancement of a technology that has not yet been demonstrated on a commercial scale; and while the bitumen would initially be exported, the project would provide for a gradual build-up of bitumen production until such time as its upgrading to synthetic crude oil could be economically justified. At that time, the synthetic crude oil would be available to serve Canadian demand as a substitute for declining conventional production and reduce Canada's dependence on imported oil. In the meantime, export would assist the Canadian balance of payments.

For these reasons, the Board is satisfied that need for the Cold Lake project remains.

## 6.2 Concept of a Phased Project Including Deferral of Upgrading

Esso noted that the general economic slowdown precludes the very large capital investment required for the previously applied-for mega-project. The phased development would allow Esso to proceed with Phases I and II now, and to undertake subsequent phases when business, market, and economic opportunities were appropriate. Upgrading would be deferred until such time as it became economically viable or until the market for diluted bitumen became restricted. Esso also stated that the phasing concept would allow incorporation of technological improvements in recovery, upgrading, and environmental protection and monitoring, into later phases.

Esso stated that while the socio-economic benefits would be very much smaller than those of the mega-project, the negative effects would also be reduced.

The Chambers of Commerce, the Cold Lake Band, and the Tribal Chiefs supported the phased approach to the project, while several other interveners inferred that they favoured the concept. All groups noted that with phasing, the benefits and impacts would be greatly reduced and spread over a longer period of time, thereby creating a climate for gradual expansion of business and employment opportunities.

The Board is satisfied that the phasing approach is more conducive to incorporation of technological advancements than would be the mega-project and that it may improve the efficiency of the proposed project as well as reduce environmental impacts. The Board also believes phasing would have a more manageable impact on the economy of the region and minimize the need for additonal infrastructure prior to commencement of operations.

The deferral of bitumen upgrading would mean the resulting production would not initially be available to serve Canada's energy needs in that there is already a domestic surplus of heavy oil. It would, however, mean the construction of upgrading facilities would take place only when they are clearly justified and would allow for the use of the best technology then available.

The Board accepts Esso's contention that an upgrader would not be a viable project at the current levels of bitumen feed available, and accepts that the advantages of the phased project outweigh any disadvantage posed by the absence of the upgrader in the early phases of the project.

The Board notes that Esso is proposing to proceed with Phases I and II at this time. Under the phased approach to development which the Board is prepared to accept, Esso would be required to submit applications for approval of subsequent phases.

### 6.3 Changes to Environmental Impacts

Esso stated that the environmental impacts of Phases I and II on air, soil, vegetation, groundwater, surface water, wildlife, and aquatic resources would be a fraction of those associated with the mega-project. The environmental impact of the fully developed phased project would be equal to or less than that already found satisfactory for the mega-project because of likely technological advances.

The Cold Lake Band expressed concern about air quality at its reserves in the Cold Lake area. It requested that Esso provide an air monitoring station on the English Bay Reserve (No. 149B) situated approximately 16 kilometres to the southeast of the proposed Phases I and II development area. Such a facility would be able to detect any changes in air quality before they became noticeable by residents of the reserve.

Esso opposed setting up a permanent monitoring station on the English Bay Reserve because it did not expect significant, if any, contaminant levels at the Reserve. It stated that acceptance of the Indian Band request might obligate it to accept all requests from groups within a similar distance of the project, but was prepared to locate a monitor in the region between the project and the Reserve.

The Cold Lake Band also requested that the Board incorporate the licences of Alberta Environment into its approval, and designate a body for the purpose of co-ordinating environmental impact information and complaints.

The Board is satisfied that the environmental impacts of Phases I and II would be much less than those of the originally proposed mega-project, and

that phasing of the project provides an opportunity for adjustments and improvements in operating details, if necessary, to minimize impacts. In the Board's judgement, environmental impacts can be limited to acceptable levels if the applicant exercises proper care in the design, installation, and operation of the proposed facilities.

With respect to the Cold Lake Band's request for an air monitoring station on the English Bay Reserve, the Board notes that the gaseous emissions of potential pollutants from Phases I and II would be small (some 1.5 tonnes per day of $SO_2$). This, coupled with the significant distance from the project to the No. 149B Reserve, satisfies the Board that a permanent monitoring station is not warranted. The Board is, however, prepared to arrange for portable monitoring equipment to be located on the reserve during the initial stages of project operations, to ensure that air quality problems do not materialize and to test the adequacy of Esso's proposed monitoring program. The Board is also prepared to assist the Cold Lake Band and other local residents in understanding the manner in which monitoring equipment operates and in interpreting the results of monitoring.

In the Board's judgement, the request for incorporation of the environmental licences into the Board's approval would not accomplish what the Cold Lake Band apparently had in mind, that is, the authority for the Board to enforce the terms of the licences. These will continue to be enforced by Alberta Environment. The Board does have general jurisdiction over environmental matters and, additionally, has field staff located in the general region. It is prepared to accept and investigate environmental complaints, and where the licences are involved, will continue to co-operate with Alberta Environment to address such complaints.

With respect to the designation of a body to handle environmental matters and complaints, the Board believes that its field office staff should fill that role. The Board will take action when it has the jurisdiction to do so, and ensure that the other appropriate government departments are involved as necessary.

The Board notes that Esso is committed to holding an annual public performance review, at which time it will present and discuss the results of its environmental monitoring program for the previous year and its plans for the following year. The Board encourages this commitment to open communication with local residents.

### 6.4 Changes to Socio-economic Effects of the Project

Esso stated that drilling and pad construction, road development, and clearing the central plant site would begin in 1983. Facilities construction would begin in 1984 with completion between mid and late 1985.

The Board is satisfied that the schedule is reasonable, would take advantage of the current economic lull, and in this respect, tend to maximize the beneficial economic impacts.

Esso submitted that the total capital expenditure for Phases I and II would be some $300 million. Sixty per cent of the materials and equipment is expected to be sourced in Alberta, and about 70 per cent is expected to originate in Canada.

The Board believes that Albertan and Canadian content should be maximized to the practical extent.

Because of the reduced scale and shorter construction period for Phases I and II, the Board agrees with Esso that the socio-economic impacts will be easily managed. The peak construction work force estimate has been reduced from 9970 to 700, and the operations and drilling work force has been reduced from 3000 to 90 people. Given the current rate of unemployment and the excess capacity in most sectors of the local economy, the project will be a welcome stimulus to the area in particular and the province in general.

For the total project, phasing over a lengthy period will also make social and other infrastructure costs more manageable, but benefits will be reduced in the sense that they will accrue over the longer period. Esso indicated, and the Board agrees, that existing infrastructure in the surrounding communities would suffice to meet demands created by the development.

The Board believes that Esso should continue its discussions with the trappers of the area respecting possible impacts on their trap lines.

## 7 AVAILABILITY OF CONDENSATE DILUENT, IMPACT ON ALBERTA USERS OF THAT DILUENT, AND MARKETING OF DILUTED BITUMEN

Esso submitted a letter from the Alberta Petroleum Marketing Commission (APMC) which confirmed that condensate requirements for Alberta heavy oil diluents would have priority status after the needs of the Bowden refinery and Alberta petrochemical plants. Accordingly, Esso suggested that the diluent needs for the Cold Lake project Phases I and II can be satisfied. If gas condensate became unavailable, Esso would use surplus light material from its Strathcona refinery as diluent. Esso also indicated that alternative sources of diluent would not affect the viability or significantly affect the phasing of the Cold Lake project.

The Board is satisfied that the use of condensate by Esso for Phases I and II, on the basis of the priority assigned such use by APMC, would not seriously impact on other Alberta users. It also notes that no parties intervened at the hearing to present evidence of an impact.

Production from Phases I and II will be classified as Cold Lake Blend and marketed by Esso outside of the Alberta prorationing system. Esso's market studies suggest that over 16 000 $m^3/d$ of such oil could be marketed in the northern tier of the U.S. The Board accepts these estimates, and concludes that production from Phases I and II would not be restricted by supplies of bitumen from other sources.

The questions of condensate availability and markets for subsequent phases would be addressed when dealing with applications for those phases.

## 8 USE OF COLD LAKE FOR MAKE-UP WATER FOR PHASES I AND II OF THE PROJECT

A significant change in the current application, as compared to the Board's findings respecting the earlier application, is Esso's request to use Cold Lake as a source of make-up water for the first two phases of its project. A water-use licence from the Water Resources Branch of Alberta Environment has been obtained. Esso stated that this would provide sufficient water for Phases I and II, and noted that the licence contains many stringent conditions and is conditional upon the Board's approval of the two initial phases.

The Cold Lake Band stated that any water extraction from Cold Lake must have no adverse effect on the lake itself or the fish, the shore line, or the shore line wildlife. Particular concern was expressed over the reliability and accuracy of a single water level monitoring station in Cold Lake, the possibility of Esso receiving approval to increase withdrawals from the lake in small increments, the possibility of the maximum safe water withdrawal being exceeded because of increased demands by priority users, and the possibility that other potential industrial users would request treatment similar to Esso's. The Cold Lake Band asked that the Board incorporate a limit on water extraction from Cold Lake into its approval.

A regional water study was completed by Alberta Environment in 1983. This addressed the protection of fisheries, wildlife, and recreational activities within the Beaver River Basin and included the Cold Lake area. The resulting Short Term Water Management Plan was adopted by Alberta Environment in March 1983 and the water licence issued to Esso is in accordance with this plan. The Board notes that the licence is restricted to a 10-year period and may only be renewed if such renewal does not conflict with an established long-term water management strategy.

The Board agrees that the use of Cold Lake as a source of water would be acceptable for the level of requirement expected for Phases I and II, namely about 3500 $m^3/d$ during steady-state operations and a maximum of about 10 000 $m^3/d$ during the initial start-up period.

The Board would expect future applications for water use for subsequent phases to be in accordance with a long-term water plan for the area, but notes that in its earlier decision, ERCB Report 79-E, it denied use of the lake for the full scale project and has not seen evidence that might change its view.

The Board notes that one of the conditions of the water licence issued for Phases I and II requires Esso to construct a separate water level gauge for the use of the Cold Lake Band in a location acceptable to the Cold Lake Band and the Controller of Water Resources. The Board is satisfied that this condition will provide the Cold Lake Band with the opportunity to independently monitor the water level.

The Board does not believe that permitting the use of Cold Lake for make-up water for Phases I and II would establish a policy that would necessarily lead to further industrial use of the lake. The Board intends to analyse any subsequent applications it receives on the basis of the impact that would

result from the total withdrawals, and would not be bound by this particular decision. It would expect that Alberta Environment would approach future applications in a similar manner.

The Board would condition any approval it issues to require the minimum practical use of Cold Lake for make-up water for Phases I and II. The Board would also require Esso to include, in any performance evaluation report to the Board and Alberta Environment, a discussion of Esso's activities and operations with respect to minimizing make-up water requirements. The Board is satisfied that these conditions and requirements, coupled with the conditions of the water licence, are sufficient at this time to ensure protection of Cold Lake.

The approval by the Board to use Cold Lake as the source of make-up water for Phases I and II would be subject to review at the time of considering applications for subsequent phases or if monitoring suggests unacceptable impacts on the lake.

## 9 OTHER MATTERS WHICH HAVE CHANGED ONLY IN RELATIVELY MINOR DETAIL OTHER THAN BEING REDUCED IN SIZE OR IMPACT OR HAVING THEIR TIMING ALTERED

The primary in situ recovery process will be cyclic steam injection as described in the original application. Recent data collected at the Leming pilot have been incorporated into the design of Phases I and II, resulting in minor refinements of the performance forecasts. Esso stated that a 20 per cent recovery level can be attained by cyclic steam stimulation, but that it would proceed with better recovery methods if they become technically and economically viable.

Although the Board has some doubt that a 20 per cent recovery level can be reached with present technology, it accepts that cyclic steam stimulation is likely to be the initial operational phase of most in situ bitumen recovery schemes, and considers it imperative that experimentation with follow-up recovery methods continue. As was its intent at the time of releasing its earlier decision, the Board would condition any approval issued to ensure that this is accomplished.

The well drilling and completion strategy presented by Esso is similar to that described in the mega-project application. The only modification proposed is a replacement of the S00-95 casing with L-80 casing with oversize buttress thread joints and collars.

The Board is satisfied that the change in well casing will improve the integrity of the injection/production wells, and otherwise remains satisfied with respect to Esso's proposed strategy. In its previous decisions, the Board required that Esso provide a monitoring program designed to ensure early detection of production casing failures. The Board has received and approved this program, but will continue to require follow-up work by Esso to improve it and to ensure that it continues to be satisfactory as operating experience is gained.

The proposed surface facilities at each well pad remain unchanged from the previous application and the Board continues to find the design satisfactory. The Board notes that the fieldgate facility, located in the north half of section 12, township 65, range 4, is not included in Esso's identified development area. The location of these facilities was not questioned by any of the interveners, and the Board would therefore include this area in any approval.

Esso proposed to use the Cambrian Formation for subsurface water disposal. This is consistent with the Board's findings as detailed in ERCB Report 79-E. The Board notes that Esso is required to obtain a separate approval before proceeding with any specific subsurface disposal well.

Esso stated that the make-up fuel requirement for Phases I and II would be some 756 000 $m^3/d$ of natural gas. The reduced requirement does not alter the Board's previous finding that the use of natural gas as a make-up fuel would be in the public interest.

With respect to exclusion of the approved experimental pilots from the Cold Lake development area, Esso stated that the pilots were not intended to be part of the mega-project. Its reasons for maintaining the pilots as they now exist include the ease of administering the experimental royalty rate, the maintenance of confidentiality of the experimental data, and maintenance of the attitude of experimentation as opposed to maximizing the economic benefit of the scheme.

The Board agrees with Esso's position on this subject and is prepared to exclude the experimental pilots from the development area. The Board notes, however, that the experimental approvals are generally restricted to a 5-year term and that the term would only be extended if the Board was satisfied that significant experimentation was continuing.

## 10 EMPLOYMENT, TRAINING, AND BUSINESS OPPORTUNITIES

This section deals with the matter of employment and business opportunities for Native people, and, as the Board explained at the beginning of the report, is a matter outside the Board's jurisdiction. Nonethless, the Board includes the evidence and its conclusion as information which may be of interest to the Lieutenant Governor in Council.

The Cold Lake Band, supported by the Tribal Chiefs, indicated that there are barriers which Native people face with respect to taking advantage of industrial employment opportunities. The Cold Lake Band identified the need for special programs to assist Native people to overcome these barriers, cited unemployment rates of 80 per cent, and expressed concern about the lack of progress toward integrating Native peoples into the work force since the original project was proposed. Of particular concern to the Cold Lake Band is the enforcement of a minimum entry level of grade 12 to most jobs and special technical training required for operating positions.

The Cold Lake Band noted that special efforts were made to allow Ft. McKay Native people to take advantage of employment opportunities at the Suncor

and Syncrude oil sands plants and requested comparable commitments from Esso in the case of the Cold Lake project.

The Cold Lake Band recommended that Alberta Government departments and agencies support training and other programs necessary to ensure local employment, as well as special efforts needed to equalize employment opportunities for Native people in the Cold Lake region. Special training of Native people included needs for pre-job training for specific tasks, utilizing methods which they find most suitable, and social training to adapt Natives to job codes and conduct.

The Cold Lake Band indicated that it discussed its recommendation concerning specific development and training programs with Esso. Esso, in turn, indicated its willingness to examine the programs it has in place at present to see how they can be adapted to deal with special problems experienced by Natives. The Cold Lake Band recommended the maximization by Esso of local employment and business opportunities with special emphasis on the utilization of Native manpower and services. In conjunction with this request, the Cold Lake Band considered it critical to have employment of Native people, and in particular Cold Lake Band members, monitored to evaluate Esso's performance in its provision of business opportunities and employment.

Esso stated that phased development of the Cold Lake project would make limited opportunities available in the short term. Therefore, progress in increasing Native opportunities would probably not be extensive in the initial phases, but would be in later phases. In regard to barriers to Native employment, Esso disclosed that its hiring policy provides for work experience to be acceptable in lieu of a grade 12 education. Given the training programs and the spirit of Esso's hiring policy, the lack of a grade 12 education should not be a barrier to employment of Native people.

Views concerning the right to recommend affirmative action were brought out at the hearing. The Cold Lake Band requested that affirmative action be undertaken to give Indians preferential treatment in training, jobs, and contracts. It was Esso's view that the Board is not authorized to condition an application with regard to affirmative action. Esso indicated that its responsibility regarding employment opportunities is limited to those practices it is already following and is prepared to continue in future.

The Board agrees that there are barriers which the Native people face in taking advantage of employment opportunities. Special training and job integration for the Indians can only be accomplished through continuous efforts by Government agencies, Esso, and Native groups. The Board encourages all involved parties to take whatever steps are practical to provide opportunities for the Native people of the region.

Without commenting on the legality of affirmative action agreements per se, the Board is of the opinion that it does not have the jurisdiction to impose such agreements by conditioning its approval. However, the Board believes that it does have jurisdiction to consider generally, as a question of impact on the local region, the matter of local business and employment opportunities. The Board is of the view that the public interest would be

served by maximizing opportunities for the Native people in the region of the proposed project. Towards this objective, the Board agrees with the concept of a co-ordinated effort on the part of both Esso and the local Indian bands to assist band members in taking advantage of employment opportunities. In the Board's view, senior officials of the concerned Government departments also have an important role to play.

## 11 DECISION

The Board is prepared to approve the concept of phasing for the Esso Cold Lake project and, to specifically approve Phases I and II. It will withdraw its earlier requests to the Lieutenant Governor in Council for an Order in Council and make a new request for an Order in Council authorizing the approval of the scheme as discussed in this report. The approval would be basically of the form set out in the appendix to this report and would be subject to the terms and conditions contained therein, but may have minor variations from that shown in the appendix.

DATED at Calgary, Alberta, on 25 August 1983.

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy, P.Eng.
Vice Chairman

V. E. Bohme

V. E. Bohme, P.Eng.
Board Member

N. Berkowitz, P.Eng.
Acting Board Member

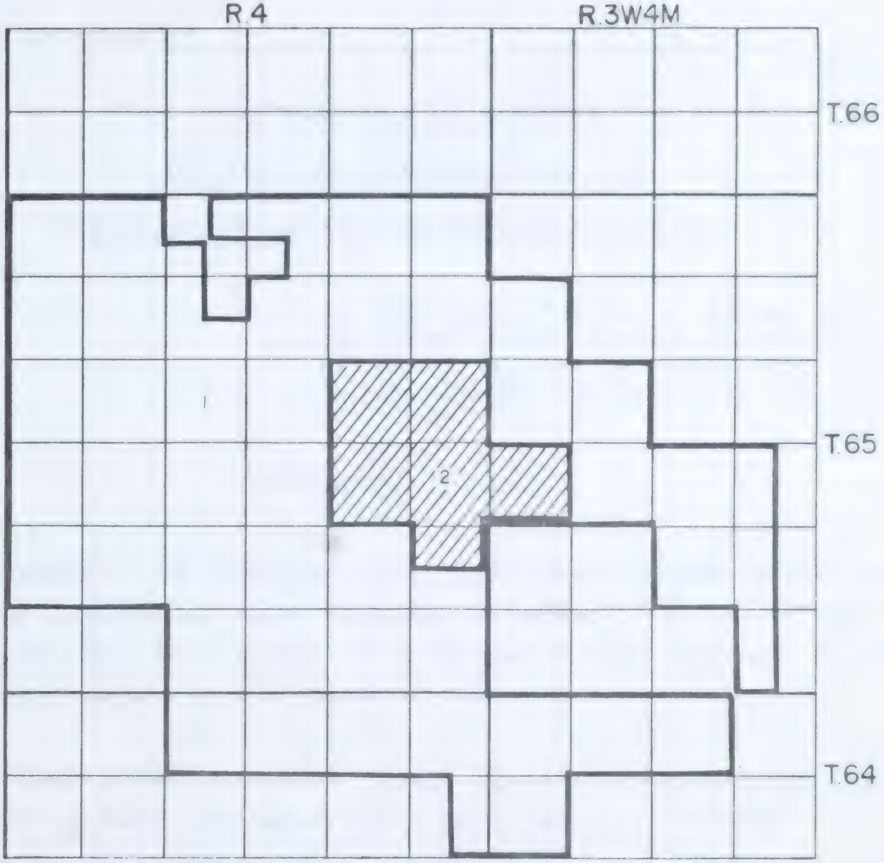
## THOSE WHO APPEARED AT THE HEARING

| Principals and Representatives (Abbreviations used in Report) | Witnesses |
|---|---|
| Esso Resources Canada Limited (Esso)<br>R. C. Pittman | G. E. Courtnage, P.Eng.<br>G. G. Mainland, P.Eng.<br>G. W. Schindel, P.Eng.<br>Dr. R. G. Gossen |
| Grand Centre and District Chamber of Commerce, Bonnyville and District Chamber of Commerce, Cold Lake Development Committee, and Northern Alberta Development Council<br>A. Sanregret | R. Shray<br>J. Bentein |
| Lakeland College<br>R. W. Shillington | |
| Basic Group of Companies<br>J. Callahan | |
| Alberta Trappers Central Association - Bonnyville & Cold Lake Local (Trappers Association)<br>T. Ganske | |
| BP Exploration Canada Ltd.<br>J. K. Donnelly | |
| Shell Canada Resources Ltd.<br>H. J. Lyon | |
| Chief and Council of Cold Lake Indian Band (Cold Lake Band)<br>L. Mandamin | C. Linklater<br>M. Piché<br>Ms. M. Minoose<br>B. Blackman |
| Tribal Chiefs Association of North Eastern Alberta (Tribal Chiefs)<br>J. Grotski | S. Sparklingeyes<br>M. Piché<br>W. Large |
| Saskatchewan Environment<br>H. Epp | H. Epp |
| Alberta Attorney General<br>G. F. Roy | |

## THOSE WHO APPEARED AT THE HEARING (cont'd)

| Principals and Representatives (Abbreviations used in Report) | Witnesses |
|---|---|
| Energy Resources Conservation Board staff (Board staff) | |
| M. J. Bruni | |
| R. G. Evans, P.Eng. | |
| F. J. Mink, P.Eng. | |
| S. L. Sills, P.Eng. | |
| J. R. Nichol, P.Eng. | |
| D. D. Fraser | |

Mr. Thomas Vladut tendered a submission but did not appear at the hearing.




APPENDIX A TO APPROVAL NO.

1. COLD LAKE PROJECT DEVELOPMENT AREA
2. PHASES I AND II DEVELOPMENT AREA

ERCB

APPENDIX
FORM OF APPROVAL *

THE PROVINCE OF ALBERTA

OIL AND GAS CONSERVATION ACT

ENERGY RESOURCES CONSERVATION BOARD

IN THE MATTER of a scheme of Esso Resources Canada Limited for the recovery of crude bitumen and products derived therefrom in the Cold Lake Area

APPROVAL NO. ______

WHEREAS Esso Resources Canada Limited has applied to the Energy Resources Conservation Board pursuant to section 31 of the Oil and Gas Conservation Act for approval of a scheme for the recovery of crude bitumen and products derived therefrom; and

WHEREAS Esso Resources Canada Limited has subsequently applied to the Energy Resources Conservation Board pursuant to section 42 of the Energy Resources Conservation Act for approval to amend the scheme; and

WHEREAS the Energy Resources Conservation Board, upon inquiry into and hearing of the application is prepared to grant the phased development of the scheme in principle and Phases I and II in particular, subject to the conditions herein contained; and

WHEREAS the Lieutenant Governor in Council, by Order in Council numbered O.C. and dated , has authorized the granting of the approval subject to certain conditions set out in the Order in Council.

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* This is only a form of approval. The approval, when issued, may have minor variations from that set out here.

THEREFORE, the Energy Resources Conservation Board, pursuant to the Oil and Gas Conservation Act, being chapter 0-5 of the Revised Statutes of Alberta, 1980, hereby orders as follows:

1. (1) The scheme of Esso Resources Canada Limited (hereinafter called "the Operator"), for the recovery of crude bitumen and products derived therefrom, taken from the area (hereinafter called "the project Development Area") outlined and marked 1 on the attachment to this approval, marked Appendix A, as such scheme is described in applications dated 9 May 1978, 2 September 1980 and 27 June 1983, in supporting material marked as exhibits and in evidence adduced at the hearing of the applications, is approved, subject to the terms and conditions herein contained.

(2) Subject to subclauses (3) and (4), nothing in this approval shall be construed as precluding any minor alteration, modification or deviation from the scheme approved or to any equipment proposed for use therein, if the minor alteration, modification or deviation is compatible with the scheme or operation so approved and will result in an improved or more efficient scheme or operation.

(3) The Operator shall notify the Board of any proposed alteration, deviation or modification to the scheme or to any equipment proposed for use therein, prior to effecting the alteration, deviation or modification.

(4) Where, in the opinion of the Board, any alteration, modification or deviation of the scheme or to any equipment proposed for use therein is

(a) not of a minor nature,

(b) not compatible with the scheme approved herein, or

(c) may not result in an improved or more efficient scheme or operation,

the alteration, modification or deviation shall not be proceeded with or effected without the further authorization of the Board.

2. (1) This approval is for a project which, subject to receipt of a subsequent approval respecting details, would result in the eventual production of up to 25 400 cubic metres per day of crude bitumen from the area outlined and marked 1 on the attachment to this approval, marked Appendix A.

(2) Phases I and II of the scheme and the immediate production by the Operator of 3000 cubic metres per day of crude bitumen from the area outlined and marked 2 on the attachment to this approval, marked Appendix A, is approved.

(3) The Operator shall make application to the Board for future phases of the scheme for production of crude bitumen above 3000 cubic metres per day.

3. The Operator shall conduct all operations to the satisfaction of the Board and in a manner that, under normal operating conditions, will permit

(a) the recovery of the practical maximum amount of crude bitumen,

(b) the gathering and utilization of the practical maximum amount of gas produced from the scheme,

(c) the practical minimum use of off-site gas for project fuel,

(d) the practical minimum use of fresh make-up water and the practical minimum disposal of water subject to the Water Resources Act and the Clean Water Act, and

(e) the efficient transportation of crude bitumen to market.

4. (1) Subject to subclause (2), the primary make-up fuel approved for use in the project is natural gas.

(2) The use by the Operator of 756 000 cubic metres per day of natural gas as make-up fuel pursuant to Phases I and II of the scheme is approved.

(3) The Operator shall, prior to 1 April of each year, provide the Board with a report detailing the make-up fuel consumption for the previous calendar year, including overall project mass balances and energy balances.

(4) The Operator shall, at the request of the Board, include any details relating to the operation of the project that may assist in interpreting the data included in the report required by subclause (3).

5. (1) The Operator shall measure and record, to the satisfaction of the Board, the volumes and other pertinent characteristics of all fluids injected and produced and other streams as may be required by the Board.

(2) Prior to 31 December 1984, the Operator shall submit plans, satisfactory to the Board, showing the proposed location and manner in which all streams referred to in subclause (1) will be measured.

(3) The measurements referred to in subclause (1) shall be made with sufficient frequency and accuracy as to allow calculation, to the satisfaction of the Board, of mass balances, energy balances and recovery efficiencies for the production processes.

6. (1) The Operator shall, commencing 30 September 1985, submit a report to the Board, by 30 September of each year, showing the proposed development plan for the next calendar year.

(2) The report required by subclause (1) shall include maps and related schedules showing

(a) the location and year of development of all existing well pads and well pads proposed to be developed during the next calendar year,

(b) the location and year of suspension or abandonment of existing well pads and well pads proposed to be suspended or abandoned during the next calendar year,

(c) satellites proposed to be relocated during the next calendar year, and

(d) such other information as the Board may require.

7. Not less than 6 months prior to the commencement of construction of Phases I and II facilities, the Operator shall file with the Board plans showing, on a topographical map, the site location of all such facilities within the Phases I and II Development Area, as well as the location of surface drainage routes, major pipelines and roadways, ponds and discard sites and such other information as the Board may require.

8. During construction of the project facilities and drilling of the project wells, the Operator shall semi-annually report the progress of construction and site development to the Board.

9. Prior to the commencement of operation of Phases I and II facilities, the Operator shall file with the Board detailed specifications for the production facilities and utility facilities, including

(a) process piping and instrument drawings,

(b) process flow diagrams with detailed material balances,

(c) operating and equipment specifications, and

(d) such other information as the Board may require.

10. (1) The Operator shall log all wells from surface to total depth by means of a spontaneous potential-resistivity or gamma ray-resistivity type logging device and such other devices as may be required to ensure sufficient depth and directional control.

(2) The Operator, unless otherwise authorized by the Board, shall drill not less than eight vertical evenly spaced wells per section through the entire Mannville zone and from those wells take core of the bitumen bearing sections of the Mannville zone, and

(a) at the Board's request, analyse portions of such cores, and

(b) provide suitable photographs of the clean cut surface of each core slabbed.

(3) Each of the wells referred to in subclause (2) shall be logged over the entire Mannville zone by means of a gamma ray-neutron density type logging device.

(4) After perforating each well, the Operator shall take an appropriate log to verify the location of the perforations with respect to the adjacent strata.

11. The Operator shall, not later than 1 April of each year, submit to the Board current estimates and appropriate supporting maps showing the volume of crude bitumen and gas in place in the sands of each formation of the Mannville Group within the Phases I and II Development Area, based on drilling completed by 31 December of the previous year.

12. Prior to the commencement of steam injection operations at any well pad, the Operator shall submit to the Board its evaluation of the volume of

crude bitumen and gas in place in the Clearwater Formation within that part of the reservoir associated with that well pad.

13. (1) Following the commencement of steam injection operations in Phases I and II, the Operator shall file with the Board and the Department of the Environment, on forms provided by or satisfactory to the Board

(a) monthly hydrocarbon and energy balance reports for

(i) the production facilities,

(ii) the utility facilities, and

(iii) the overall project,

(b) monthly water balance report for the overall project, and

(c) a performance evaluation report summarizing all activities and operations carried out, including

(i) graphical presentations of rates versus time and cumulative amounts versus time, of each type of fluid injected or produced for each well pad, each disposal well and for the overall project,

(ii) a tabulation of cumulative bitumen production, to the end of the report period, from each well and well pad, and of bitumen recovery from each well pad expresed as a percentage of the assigned volume of bitumen in place,

(iii) hydrocarbon, energy and water balances over the report period, in a format similar to that required monthly by subclause (1), paragraph (a),

(iv) details of any deviations from the annual development plan,

(v) a discussion of any unique production or injection problems encountered at specific wells,

(vi) details of any casing failures and major operating incidents,

(vii) a review of any operations conducted to reclaim or dispose of sand and oily waste generated by the project,

(viii) an assessment of the efficiency of injection/production operations, and water treatment operations,

(ix) a review of operations conducted to minimize the make-up water requirements, and

(x) such other information as the Board may require.

(2) The reports required by subclause (1), paragraphs (a) and (b) shall be filed by the 15th day of the month following that month for which the balances are being reported.

(3) Duplicate copies of the reports required by subclause (1), paragraph (c) shall be submitted semi-annually for the first 3 years, for operating periods ending 30 June and 31 December, and annually thereafter, and shall be filed within 60 days of the expiration of the report period for semi-annual reports and within 90 days of the expiration of the report period for annual reports.

14. Unless otherwise expressly authorized by the Board, the Operator shall conduct all drilling operations using a water-based mud and not

introduce any toxic or potentially toxic additives to any muds or fluids used directly in the drilling of wells associated with the scheme.

15. The Operator shall install surface casing, in a manner satisfactory to the Board, through the glacial drift on all waste water disposal wells.

16. The Operator shall, not later than 1 January 1985, submit to the Board and the Department of the Environment, a monitoring program satisfactory to the Board and the Department of the Environment, to ensure early detection of any contamination of fresh water aquifers or surficial ground waters that may be caused by scheme operations.

17. The Operator shall take such steps and effect such measures as may be necessary in the completing and operation of wells to prevent production casing failures.

18. The Operator shall satisfy the Department of the Environment with respect to land surface reclamation.

19. Prior to the commencement of steam injection operations, and in no circumstances later than 1 January 1985, the Operator shall submit to the Board and the Department of the Environment, detailed plans for the reclamation or disposal of all sand and oily waste materials generated by the project.

20. The Operator shall not vent, flare or waste any gaseous or liquid hydrocarbons except in cases of emergency, unless otherwise authorized in writing by the Board.

21. The Operator shall, not later than 1 January 1985, submit to the Board, spill contingency plans for the scheme in the detail specified in the Board's Interim Directive No. ID-OG-PL 75-1.

22. (1) When bitumen, salt water or other liquid other than fresh water is spilled from any equipment or facility associated with the scheme, the Operator shall take immediate steps to contain and clean up the spill.

(2) Where a spill occurs from a facility described in subclause (1) and

(a) the liquid is not confined to the site of the facility from which the spill occurred, or

(b) the volume of liquid spilled is in excess of 2 cubic metres,

the Operator shall immediately report the size and location of the spill to the Board by the quickest and most effective means.

(3) When so directed by the Board, a report made pursuant to subclause (2) shall, within 2 weeks of the date of the spill, be confirmed in a written report to the Board and be supplemented with at least the following additional information:

(a) the time the spill occurred,

(b) a description of the circumstances leading to the spill,

(c) a discussion of the spill containment and recovery procedures,

(d) a discussion of steps to be taken to prevent similar spills in the future, and

(e) an outline of the proposed spill site rehabilitation program.

23. The Operator shall comply with the Clean Air Act in matters relating to source and ambient air monitoring.

24. (1) The use of water from Cold Lake as a fresh make-up water for Phases I and II is approved in accordance with the terms and conditions of Interim Licence 12298 issued pursuant to the Water Resources Act.

(2) No source or method of providing additional fresh make-up water to the project shall be proceeded with by the Operator without the express written authorization of the Board and the Department of the Environment.

25. (1) No surface disposal of any aqueous wastes from the project shall be proceeded with unless

(a) the Operator has submitted a report to the Board and the Department of the Environment describing alternative methods for such disposal, and

(b) the method of the surface disposal of aqueous wastes is expressly authorized in writing by the Board and the Department of the Environment.

26. (1) Subsurface disposal of aqueous wastes from the project shall be to the Cambrian Formation.

(2) The Operator shall obtain written authorization from the Board as to the use of any particular well for subsurface disposal.

27. (1) The Operator, unless given the express written consent of the Board to do otherwise, shall maintain between the location of steamed wells and wells being drilled, a separation adequate to ensure that zones pressured by injected steam are not encountered by wells being drilled.

(2) The Operator shall undertake and submit to the Board prior to the commencement of steam injection operations, a study respecting the minimum safe separation between the location of steamed wells and wells being drilled.

28. The Operator, subject to such terms and conditions as may be prescribed by the Board upon considering an application therefor, shall undertake extensive field investigations of in situ combustion, steam flooding and any other alternative or follow-up recovery method that the Operator believes may have potential application in the Clearwater Formation.

29. The Operator shall conduct recovery tests, satisfactory to the Board, in the McMurray and Grand Rapids Formations in the project Development Area to determine the practicality of recovering bitumen from these formations and provide the results of such tests to the Board.

30. (1) Unless otherwise permitted by the Board, cyclic steam stimulation operations, having commenced at a well pad, shall continue until the well pad has produced a minimum of 20 per cent of the in-place volume of crude bitumen assigned to that well pad by the Board.

(2) Where the Operator proposes to cease cyclic steam stimulation operations at a well pad that has produced less than 20 per cent of the in-place volume of crude bitumen, and the Board's consent therefor is sought, the Operator shall advise the Board as to the following:

(a) the reason for proposing to cease cyclic steam stimulation operations,

(b) details of individual well workovers and recompletions attempted,

(c) details of any infill drilling attempted,

(d) detailed economics of continuing operations, and

(e) future plans for the well pad with reference to possible follow-up recovery techniques that could be applied and other zones that could be exploited.

31. (1) No well may be abandoned without prior written Board approval.

(2) Where the Operator proposes to abandon a well and the Board's consent therefor is sought, the Operator shall advise the Board as to the following:

(a) the reason for the proposed abandonment,

(b) the effect of abandoning the well on the bitumen recovery ultimately achievable from that part of the reservoir associated with the well,

(c) plans for recovering any portion of the remaining bitumen in place, and

(d) plans for recovering bitumen from other zones penetrated by the well.

32. Notwithstanding any date by which any work, act, matter or thing is by this approval required to be done, performed or completed, the Board, if it considers it proper to do so, may by stipulation alter the date specified.

33. (1) Attached hereto is Appendix B and made part of this approval is the order of the Lieutenant Governor in Council authorizing the granting of the approval.

(2) This approval is subject to the terms and conditions, if any, prescribed by the order of the Lieutenant Governor in Council set out in Appendix B.

34. The Operator shall not

(a) assign this approval, or

(b) alter its control of the operation of the scheme,

without consent in writing of the Board, which may, with the authorization of the Lieutenant Governor in Council, be given by the Board upon application therefor.

35. (1) The Board may,

(a) upon its own motion, or

(b) upon the application of an interested person,

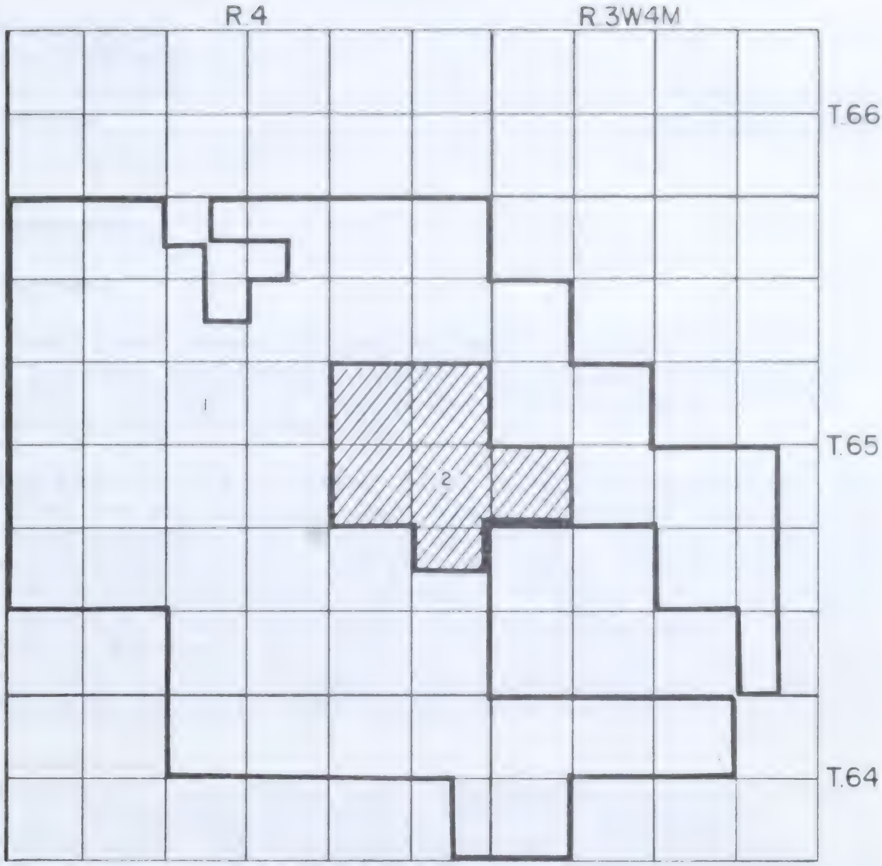
recind or amend this approval at any time if, in the opinion of the Board, circumstances so warrant.

(2) This approval, unless rescinded before that date, expires on 31 December 2010, unless upon application by the Operator a later date is stipulated by the Board.

MADE at the City of Calgary, in the Province of Alberta, this day of , 19 .

ENERGY RESOURCES CONSERVATION BOARD

Vernon Millard
Chairman




APPENDIX A TO APPROVAL NO.

1. COLD LAKE PROJECT DEVELOPMENT AREA
2. PHASES I AND II DEVELOPMENT AREA

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

SHELL PROPOSED MOOSE
AND WHISKEY PIPELINES
AND RELATED FACILITIES
KANANASKIS AREA

Decision D 83-22
Application 830603

# 1 INTRODUCTION

## 1.1 Background

In 1981, Shell Canada Resources Limited (Shell) applied for permits to construct pipelines and associated facilities to gather sour gas from wells located in the Moose and Whiskey fields and transport it to the Quirk Creek gas plant for processing.

In ERCB Decision Report 82-E (report 82-E) the Board concluded that the proposed pipelines and facilities were needed, the Quirk Creek processing location was appropriate, the pipeline design would provide a high degree of confidence in its integrity, and that the impact from the pipeline on the Elbow River watershed would be minimal. It denied the applications, however, because of concern for public safety arising from the expectation of limited dispersion of sour gas if an accidental release occurred, and the proximity to the Kananaskis Country Interdepartmental Committee's (KCIC) recreation facilities near the Ice Caves and along the Elbow River valley.

Subsequently, a Shell/Government task force initiated a study to assess the risks and consequences of potential hydrogen sulphide ($H_2S$) releases in the area. Valley meteorological characteristics were determined and, along with the results of a tracer gas field verification study, were used in a numerical model to simulate dispersion in complex terrain for various $H_2S$ release cases. After a risk assessment of the proposed pipelines and related facilities was done, Shell applied to the Board to have it reconsider its decision.

## 1.2 The Application

Shell applied pursuant to section 42 of the Energy Resources Conservation Act to have the Board review its report 82-E concerning public safety, to rescind or vary its prior order, and to permit the construction of the pipelines and related facilities as originally applied for.

In its letter of application, Shell agreed to meet two conditions specified by the Minister of Energy and Natural Resources (E&NR):

- That the pipeline segment $H_2S$ volumes be limited to those used in the risk study.

- That well servicing or workovers be scheduled outside the heaviest portion of the recreation season and that E&NR receive about 10 days advance notice of any such activity so that it can temporarily close the area to public access.

### 1.3 The Hearing

The application was considered at a public hearing in Calgary, Alberta, on 29 August 1983, with V. Millard, N. Strom, P.Eng., and R. G. Evans, P.Eng., sitting.

THOSE WHO APPEARED AT THE HEARING

| Principals and Representatives (Abbreviations used in Report) | Witnesses |
|---|---|
| Shell Canada Resources Limited (Shell)<br>D. O. Sabey, Q.C.<br>A.P.G. Walker | R. P. Cej, P.Eng.<br>T. C. Olson, P.Eng.<br>J. F. Fahner, P.Eng.<br><br>F. G. Bercha, P.Eng.<br>R. I. MacDonald<br>of F. G. Bercha and Associates Limited |
| Esso Resources Canada Limited (Esso)<br>R. C. Pittman | |
| Energy Resources Conservation Board staff<br>K. F. Miller<br>G. C. Dunn, P.Eng.<br>H. W. Knox, P.Eng.<br>W. Roberts, E.I.T. | |

The Square Butte Community Association and G. Tarves filed submissions but did not appear at the hearing.

## 2 PUBLIC SAFETY

### 2.1 Views of Shell

In response to public safety concerns expressed at the earlier hearing, Shell filed additional information to describe and quantify risks which

may be encountered by allowing the coexistence of the proposed sour gas production facilities together with existing and KCIC recreational facilities. Three studies were filed in support of Shell's application:

- Alberta Environment, 1983. Dispersion Climatology of the Moose Mountain Area. Edmonton, Alberta.
- Alberta Environment, 1983. Numerical Modelling and Field Verification for the Shell Moose Mountain Sour Gas Project. Edmonton, Alberta.
- F. G. Bercha and Associates Limited, 1983. Risk Analysis of Shell Proposed Moose Mountain Pipelines and Related Facilities. Calgary, Alberta.

The Dispersion Climatology study concluded that airflow under stable valley drainage conditions (i.e. nocturnal down-valley flow) is more turbulent than airflow over plains under stable conditions. In addition, up-valley flows (afternoon) were described as being comparable to moderately unstable conditions in the plains. The study was conducted over a 1-month period (September, 1982) and was considered representative for all months of the year. This conclusion was reached by comparing four weather map types for Alberta and long-term weather data to the observed valley conditions during September 1982. It was observed that the microclimatology of the local valleys of interest did not vary with regional weather patterns and also varied only modestly on a seasonal basis.

The conclusion of this report was that, owing to persistent air turbulence, the dispersion characteristics for the area were superior to those encountered on the plains.

The Numerical Modelling and Field Verification study describes a series of computer model $H_2S$ dispersions for this site-specific mountain valley terrain. The IMPACT[1] model, which incorporates far more of the physical characteristics of diffusion in complex terrain than do Gaussian models ordinarily used for plains conditions, was selected to deal with the mountain valley terrain under consideration. The model was calibrated with the results of tracer gas field verification tests and then used to predict $H_2S$ concentrations in the areas for a series of hypothetical sour gas releases.

The information from the dispersion model was then combined with sour gas release event probabilities to produce predicted risks as

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1 Integrated Model for Plumes and Atmospherics in Complex Terrain.

described in the Risk Analysis. The event probabilities were derived from a fault-tree analysis for the Shell sour gas facilities. The analysis technique combines the probabilities of a series of events to predict the probability of (or potential frequency of) failure events leading to severe health hazards or loss of life.

The risk analysis used failure statistics from various sources to predict and/or verify the fault-tree probabilities for both pipeline and well failures. The results indicate an average individual risk of approximately $2.0 \times 10^{-7}$ with an upper bound accident probability of $1.21 \times 10^{-3}$ based on expected usage.

Shell representatives and Dr. Bercha (Shell's risk consultant) both expressed the opinion that these risks were acceptable compared to other common day-to-day risks. Dr. Bercha stated that the risk from the pipeline facility during a visit to the Ice Caves would be much lower than the risk associated with driving to the site.

## 2.2 Views of the Board

At the initial hearing, the Government expressed serious concern about the proposed pipelines because of potential danger to public safety. It contended that the Canyon Creek road, the Ice Caves parking lot, the 25-unit Ice Caves day-use site, and the Ice Caves should be designated a public facility because of the unique topography (see pages 35 to 37 of report 82-E). It postulated that any escape of $H_2S$ in that area would not disperse in the manner assumed in Interim Directive ID 81-3[2] and that the released $H_2S$ might be retained within the walls of the canyon as a cloud of gas moving toward the Elbow River valley. The Government also contended that a specific risk analysis should be made based upon meaningful atmospheric data.

The Board agreed that the public safety issue was of prime importance and while it believed that the probability of an $H_2S$ release would be low, it was of the view that little dispersion would occur in the Moose-Dome and Canyon Creek valleys and that heavier-than-air $H_2S$ from an accidental sour gas release would move down those valleys in a concentrated cloud. Based on that interpretation, it concluded that most or all of the facilities identified by the Government as planned for the area should be treated as public facilities under ID 81-3. Since the proposed pipeline location would not meet the set back distance requirements for public facilities, the Board denied the applications for public safety reasons.

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2 Energy Resources Conservation Board, 1981. Minimum Distance Requirements Separating New Sour Gas Facilities From Residential And Other Developments. Interim Directive ID 81-3. Calgary, Alberta.

The Board considers the new evidence regarding the valley climatology very significant additional information on which to assess the situation. It is apparent that the previous dispersion postulation was not accurate and that turbulent mixing in the canyon is prevalent and results in more effective dispersion. Additionally, the Board believes that the IMPACT model results (verified by field tracer tests) reinforce the expectation of rapid dispersion of any accidental $H_2S$ release in the valley.

The IMPACT model studies also show quite rapid dispersion occurring even at uncontrolled releases from wells in the Moose-Dome valley. While the Board accepts the results, it nonetheless agrees that the closure of public access to the Canyon Creek and Ice Caves area would be a wise precaution to take during short periods when well workover or new well completions are underway.

The Bercha risk analysis evaluated the level of risk that would be associated with the proposed pipelines and found it to be orders of magnitude less than the transportation risk associated with a visit to the Ice Caves. These results reinforce the Board's previous view that the risk of a fatality due to exposure to sour gas from the proposed facilities is exceedingly low. Having regard for the new evidence, the Board is satisfied that the road and other planned facilities need not be defined as "public facilities" under ID 81-3.

The Board notes that the recent risk study evaluated a specific combination of proposed sour gas installations and recreation plans. However, should this combination be significantly altered in the future, it believes further risk analysis may be necessary.

In summary, the Government is now satisfied that the proposed pipeline and related facilities are compatible with planned recreation development and operations in the Ice Caves area. A review of the new evidence by the Board indicates there is no longer justification to define the road and other facilities as "public facilities". The Board concludes, therefore, that the proposed pipelines meet the specific policy requirements of ID 81-3, as well as reasonable safety requirements, and should be approved.

## 3 PERMIT CONDITIONS

In its application, Shell stated it would accept two pipeline permit conditions which, it stated, the Government believed should be required to eliminate remaining areas of risk. Specifically, the first condition was to limit pipeline segment potential $H_2S$ release volumes (supplementary to normal licensing restrictions) to be consistent with the "average annual release volumes" used in the risk study. The second condition addressed advance notification (10 days) of E&NR staff of well servicing, workover, or completion operations so that public access to the area could be properly restricted. The condition also emphasized that these operations should not be undertaken during peak recreation usage periods.

Shell stated that the $H_2S$ release volumes used in the risk analysis were calculated using expected operating pressures and maximum $H_2S$ concentrations under operating conditions. It compared the gathering system design maximum operating pressure (MOP) of 12.4 megapascals (MPa) with the estimated actual operating pressure of 5.5 MPa and the proposed licence $H_2S$ concentration of 400 mol/kmol with the expected $H_2S$ concentration range of 70 to 400 mol/kmol. Similarly for the main pipeline, the design MOP would be 14.9 MPa while the actual operating pressure would be about 7.6 MPa and the proposed licence $H_2S$ concentration would be 250 mol/kmol while the actual $H_2S$ concentration expected would be about 200 mol/kmol. Shell stated that using the expected operating parameters allowed for more realistic dispersion simulations of $H_2S$ releases in the area.

The Board appreciates that pipeline segment potential $H_2S$ release volumes are dependent on a number of operating parameters and agrees that limiting the volumes to those used in the risk analysis will help minimize risk. Therefore, it will require Shell to operate its system to limit the pipeline segment $H_2S$ release volumes to those used in the risk analysis.

Further to its comments in section 2 about closure of public access to the Canyon Creek and Ice Caves area during well servicing, workover, or completion operations, the Board believes that communication between Shell and the Government at all levels is vital to the successful operation of the entire gas gathering system. Therefore, it will not only condition the pipeline permits to require 10 days advance notice to E&NR of planned well servicing, workover, or completion operations, but also will amend the well licences for the Moose Field to include the same notification requirements.

## 4 DECISION

The Board continues to be satisfied that installation of the proposed pipelines and related facilities are in the public interest and that the Quirk Creek gas plant is the most suitable processing location.

Therefore, having particular regard for the conclusions cited in section 2 of this report, the Board has decided to rescind its previous ruling and approve the facilities applied for by Shell Canada Resources Limited.

Accordingly, the Board is prepared to issue the necessary permits and approvals to construct the pipelines and related facilities (Applications 810148, 810149, 810150, 810663, 810714, 810715, and 810716) subject to the following conditions:

(1) The pipeline shall be operated such that pipeline segment $H_2S$ release volumes shall not exceed those used in the risk analysis.

(2) Shell shall provide at least 10 days notice to the Department of Energy and Natural Resources before commencing any well servicing, workover, or completion operations in the Moose Field.

The permits will be issued after receipt of the approval of the Minister of the Environment respecting environmental matters.

The Board has also decided to amend the individual well licences in the Moose Field to require 10 days advance notification of well servicing, workover, or completion operations to the Department of Energy and Natural Resources.

ISSUED at Calgary, Alberta on 8 September 1983.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

N. Strom, P.Eng.
Board Member

R. G. Evans, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta



1983 ADMINISTRATION FEE APPEAL Panel Report D83-23

## 1 INTRODUCTION

The oil and gas industry in Alberta is required to fund 50 per cent of the net estimated oil and gas related expenditures of the Energy Resources Conservation Board through the levy of an administration fee on wells and oil sands projects. The Oil and Gas Conservation Act and the Regulations thereunder[1] provide for appeals of the administration fee levy and the hearing of such appeals. The single appeal made against the 1983 administration fee was heard on September 13, 1983 by a panel consisting of V. E. Bohme, Board Member, and F. J. Mink, Acting Board Member.

## 2 NOTICE OF LEVY

The Notices of Administration Fee were mailed on 27 June 1983 to 413 operators. The deadline for submission of appeals was 28 July 1983 and the final date for payment was set at 25 August 1983.

## 3 VIEWS OF THE APPELLANT

One submission was received from Lorne H. Reed and Associates Ltd. who appealed the $2,000.00 fee levied on the well located at 7-30-24-9W4. The appellant contended that the fee was excessive in that the well ceased production on 16 December 1982 and is unlikely to produce again.

## 4 BOARD STAFF SUBMISSION

The Board's records indicate that there are two wells producing at this location. The event sequence 0 well takes production from the Banff C pool and the event sequence 2 well produces from the Mannville SSS pool. Each well was levied a $1,000.00 fee based on the reported 1982 production. The operator amended its production reports in 1983 by reducing the Mannville SSS production to 67.0 $10^3$ $m^3$ and increasing the Banff C production to 5 387.5 $10^3$ $m^3$. When the amended production volumes are applied to the 1983 fee schedule, the event sequence 0 well changes from a class 6 well to a class 7 well requiring a fee of $1,300.00 and the event sequence 2 well changes from a class 6 well to a class 2 well requiring that no fee be paid. Board staff recommended that this change in fees be allowed.

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1 Oil and Gas Conservation Act - Part 11
Oil and Gas Conservation Regulations - Part 16

## 5 VIEWS OF THE PANEL

The panel agrees that the revised 1982 production volumes should be used to determine the 1983 fees. With regard to the appellant's further contention that the Banff C pool has not produced since 16 December 1982 and should therefore not be liable to a fee, the panel notes the following points:

- The well produced 5 387.5 $10^3$ $m^3$ of gas during 1982.
- The well does not fall into any of the "exempted well" categories defined in Section 16.050 of the Regulations, and
- Section 16.060 of the Regulations reads, in part, "An administration fee shall be imposed on each well ... that is not exempted by these regulations ..."

Section 16.060 requires that the Board impose a fee on any well that is not exempted by the Regulations. Although there may be circumstances where the Board may vary a fee imposed or exempt a well from the fee, the panel do not consider that such circumstances apply in the present appeal.

## 6 RECOMMENDATION

The panel recommends that the Board grant that portion of the appeal by applying the following actual 1982 production data to the 1983 fees payable:

| Well | 1982 Production | 1983 Class | 1983 Fee |
|---|---|---|---|
| 00/07-30-024-09W4/0 | 5 387.5 $10^3$ $m^3$ | 7 | $1,300.00 |
| 00/07-30-024-09W4/2 | 67.0 $10^3$ $m^3$ | 2 | 0.00 |

With respect to the request for a further reduction in fees for the well 00/07-30-024-09W4/0, the panel recommends that the Board deny the appeal.

DATED at Calgary, Alberta on 23 September 1983

ENERGY RESOURCES CONSERVATION BOARD

V. E. Bohme
Board Member

F. J. Mink
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

TEXACO CANADA RESOURCES LTD.
APPLICATION FOR TERTIARY MISCIBLE SCHEME
WIZARD LAKE D-3A POOL

Decision D 83-24
Application 830222

# 1. INTRODUCTION

## 1.1 The Application

Texaco Canada Resources Ltd. (Texaco) applied, pursuant to section 26 of the Oil and Gas Conservation Act, for approval to extend the vertical hydrocarbon miscible flood into the waterflushed zone of the Wizard Lake D-3A Pool (the Pool).

## 1.2 Interventions

Although Chevron Canada Resources Limited and Gulf Canada Resources Inc. reserved the right to intervene for the purpose of cross-examination, neither party exercised this right during the hearing. However, Gulf Canada expressed support for the application at the close of the hearing.

## 1.3 Background

The Wizard Lake D-3A Pool was discovered in 1951 and produced under primary depletion until 1969. This primary depletion mechanism consisted of fluid expansion, solution gas drive, secondary gas cap expansion with gravity segregation and a vertical water drive. The pool has an average porosity of approximately 9.6 per cent and appears to exhibit a slightly increasing porosity towards the reef base. Average pool initial water saturation has been estimated at 7 per cent. The pool originally contained hydrocarbon vertical relief of approximately 200 metres, with the pool profile illustrated in exaggerated vertical scale on the attached Figure 1.

On 26 May 1969 the Board issued Decision 69-8 approving Application No. 4401, by Texaco Exploration Company, for a vertical hydrocarbon miscible flood of the Pool. Referring to profile (A) in Figure 1, Texaco proposed to inject a first-contact miscible solvent at the existing gas-oil interface of 1056 mss. Texaco was given approval to allow the oil-water contact to rise to 1207 mss as the physical properties of the pool and the economics indicated that solvent flooding below this elevation would not be feasible. Specifically, Texaco was concerned about factors such as the increased requirements of solvent and gas, the loss of well productivity on the flanks resulting in the loss of oil and solvent, and increased "sandwich" losses. The scheme commenced in 1969, and during the subsequent years of

operation the oil-water contact did rise some 3.5 metres above 1207 mss but was subsequently lowered by controlled injection and is currently at the approved level of 1207 mss. The current application proposes to control injection in such a manner as to resaturate the zone between 1207 mss and 1230 mss, and extend the miscible flooding through that region.

### 1.4 Hearing and Appearances

A public hearing of the application was held on 26 July 1983, with G. J. DeSorcy, P.Eng., N. Strom, P.Eng., and C. J. Goodman, P.Eng., sitting.

The Board, viewing Texaco's proposal to be in the public interest because it would: increase recovery of oil; promote the economic, orderly and efficient development of the resources of the Province; and bring economic benefits to Texaco and the Province, announced at the conclusion of the hearing that it would approve the scheme and would disclose details respecting conditions of approval in a decision report. It went on to indicate that details of its ruling respecting incremental tertiary oil reserves would be included in the decision report. However, the Board indicated that it was satisfied that the increment would not be less than 4 000 $10^3 m^3$.

The following table lists appearance at the hearing.

THOSE WHO APPEARED AT THE HEARING

| Principals and Representatives (Abbreviations used in Report) | Witnesses |
|---|---|
| Texaco Canada Resources Ltd. (Texaco)<br>Mr. W. Muscoby | D. L. Archer, P.Eng.<br>D. R. Guise, P.Eng.<br>P. Massarotto, P.Eng.<br>P. E. MacDonell, P.Eng.<br>Dr. N. Mungan, P.Eng. (of Mungan Petroleum Consultants Ltd.) |
| Chevron Canada Resources Limited (Chevron)<br>Mr. D.G. Guest | |
| Gulf Canada Resources Inc. (Gulf)<br>Mr. V. Cheung | |
| Energy Resources Conservation Board staff<br>R. J. Willard, P.Eng.<br>T. M. Hurst | |

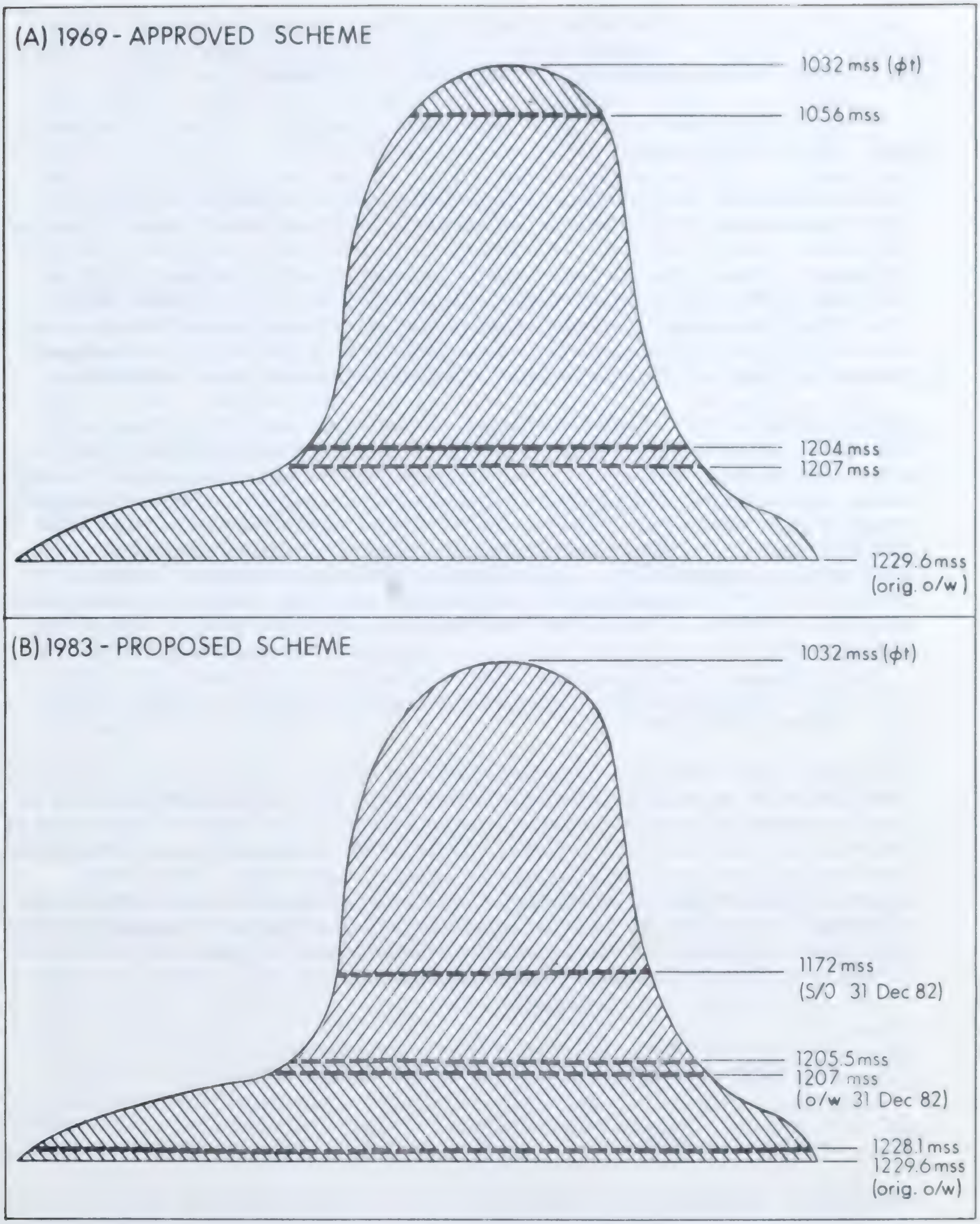



FIGURE 1 - WIZARD LAKE D-3A POOL

## 2. PROPOSED OPERATING STRATEGY - A SUMMARY

### 2.1 Views of Texaco

Texaco proposed a depletion strategy which would enable it to recover a high percentage of the residual oil saturation in the waterflushed region of the Wizard Lake D-3A Pool. As shown on profile (B) in Figure 1, Texaco proposed to lower the oil-water (O/W) contact from the current depth of 1207 mss to the original O/W contact of 1229.6 mss. The miscible flood would then continue downward through the previously waterflushed zone, with the incremental oil recovery essentially being the difference between waterflood residual oil (SORW) and miscible flood residual oil (SORM).

Texaco would have to inject additional solvent over and above that currently approved in order to miscibly flood the previously waterflushed zone. Many wells will have to be deepened and Texaco also planned to drill seven new wells into the flanks of the pool to ensure the proposed tertiary reserves are recovered. Texaco believed that controlling the rate of fall of the O/W contact to the minimum rate practical would promote maximum resaturation reversibility. To achieve maximum resaturation Texaco proposed an average rate of fall of 2 metres per year, with a maximum rate of fall of 3 metres in any given year to allow some flexibility in operating the project.

### 2.2 Views of the Board

The Board notes that the excellent qualities of the Wizard Lake D-3A Pool combined with careful engineering management by Texaco have resulted in ideally controlled miscible flood operations over the 14 years of operation of the existing miscible flood project. This gives the Board the confidence to conclude that the currently proposed scheme would have a very high degree of probability of success. Also, the high degree of success of the miscible flood up to now and the expected excellent reservoir quality in the waterflushed portion of the reservoir, indicate the proposed scheme should provide significant incremental oil recovery.

## 3 FACTORS AFFECTING ESTABLISHED RESERVES

### 3.1 In-Place Reserves

#### 3.1.1 Views of Texaco

Texaco determined the volumetric in-place reserve to be 62 239 $10^3$ $m^3$ but throughout its application, adjusted all calculations to reflect its material balance in-place reserve of 62 054 $10^3$ $m^3$.

Texaco reported that the average porosity, rock volume and pore volume distribution were unchanged from its 1968 submission. Texaco commented that porosity was determined from both core and log values. Utilizing only core data in very vuggy carbonates was believed to give a pessimistic average porosity. Texaco acknowledged that there was limited data to confirm the porosity of the lower portion of the pool, and also, that limited well control in the flank areas made reserve determinations in these areas somewhat interpretive.

3.1.2 Views of the Board

The Board's currently recognized in-place reserve of 61 200 $10^3$ $m^3$ represents close agreement between volumetric and material balance determinations. Although there is little new wellbore information, performance history does indicate the Board assigned in-place reserve to be slightly low. Accordingly, the assigned average pool porosity is being increased from 9.5 per cent to 9.6 per cent and the rock volume increased slightly to recognize additional reserves on the flank of the pool. The result of these changes is to increase the in-place reserve to 62 000 $10^3$ $m^3$, agreeing with that proposed by Texaco. Further, the distribution of reserves on a hydrocarbon pore volume versus depth basis, using the Board's isopach, is in very close agreement with that presented by Texaco. Therefore, Texaco's values of in-place reserves for various segments of the reservoir have been adopted for recovery calculations.

The Board considers it desirable to pursue a comprehensive core and logging program in conjunction with the anticipated well deepening and drilling program to better define the reservoir characteristics in the planned reflush region.

3.2 Reversibility

3.2.1 Views of Texaco

As the O/W contact has risen to 1207 mss, the water has flushed oil from the pore space leaving an unrecoverable residual oil saturation (SORW). Texaco stated that lowering the oil-water contact to its original depth and miscibly flooding the resaturated zone was technically feasible. Texaco believed that resaturation of the water-displaced zone by oil would re-establish initial oil saturations and expected that the miscible displacement efficiency in the reflushed zone would match the performance in the main oil column. In support of its views Texaco submitted a special core study involving slow displacement flush-reverse flush (oil resaturation) tests followed by miscible displacement, together with capillary pressure curves and references to similar, related studies.

In response to questioning, Texaco commented that the water saturation differences in the three core tests of plus 10 per cent and 20 per cent and negative 7 per cent after the reverse flush was within expected experimental error for this type of test. Further, Texaco did not consider

that water saturations in the test samples, which exceeded field conditions by 3 to 4 times, would invalidate its overall conclusions that reflush to original oil saturation would be achieved.

Texaco identified the following critical characteristics necessary to ensure complete reversibility:

- o the vugular porosity is well developed and has good capillary continuity with the matrix;
- o the in-situ permeability is several hundred millidarcies (md) or higher; and
- o the displacement is slow enough to permit frontal stability and capillary equilibrium to prevail.

Texaco concluded that all of the above conditions would be met in the Wizard Lake D-3A Pool.

3.2.2 Views of the Board

The Board observes that neither Texaco's laboratory studies nor the referenced work by industry has been able to fully demonstrate the achievement of complete reversibility in core tests and that there has never been a field test conducted. Nonetheless the Board believes that the demonstrated excellent qualities of the Wizard Lake D-3A Pool, and the highly favorable capillary character and gravity phenomena give very strong support to the expectation that virtually complete oil resaturation can be achieved.

3.3 Residual Oil Saturation

3.3.1 Views of Texaco

Texaco stated that it considered a residual oil saturation to waterflood (SORW) of 0.30 as likely near the minimum that exists in the waterflushed zone. In support, Texaco refiled the laboratory results of D-3 core tests, submitted in the previous 1968 miscible flood application, which indicated an SORW of 0.304 at a connate water saturation of 7 per cent and zero gas saturation. Texaco noted that the Board at that time had assigned an SORW of 0.30.

Texaco further referred to a 1978 Bonnie Glen performance report that was successful in matching history using an SORW of 0.25 at the then applicable gas saturation of 0.10, implying that residual hydrocarbon saturation under water displacement was 0.30 or higher. Also, it referred to a recent waterflood application which provided a statistical survey of displacement tests for West Pembina, Acheson and Meekwap carbonate core samples indicating even higher SORW's; however, it was not aware that this information was subsequently discounted by many of the operators concerned.

Texaco, during the hearing, filed a material balance study involving a history match of O/W contact movement assuming different SORW's. Under cross-examination Texaco agreed that the study suggested SORW could range from 0.25 to 0.35 and that both volumetric interpretation and production variations could influence the accuracy of the study. Texaco calculated, at the Board's request, the sensitivity of miscible flood efficiency utilizing SORW's within this range and obtained oil recovery values ranging from 95.5 to 102 per cent with the lower value applicable at SORW of 0.25.

To better confirm SORW for the Pool, Texaco submitted a proposal to conduct a program of testing both pressure and conventional core samples and conduct special logging surveys during well deepening and flank drilling activity.

3.3.2 Views of the Board

Over the past 25 years the Board has prompted the oil industry to perform a variety of field and laboratory tests that would lead to reliable estimates of residual oil saturation under water displacement. The accurate determination of SORW and its distribution is very significant, if not decisive, when considering the application of tertiary recovery methods to previously water-displaced oil zones.

The Board believes that laboratory tests by themselves frequently do not allow reliable estimates of SORW, although they are of considerable indirect value in such determination. This probably derives primarily because of the difficulty in representing field conditions in a laboratory and because it is common for the laboratory data to show a wide random scattering. At the same time, the Board has been cautious in completely accepting SORW from history-matches due to their dependency on the combined effects of pore volume versus depth determination and potential errors in O/W contact measurement, although this information is of great assistance in "closing" on a sound engineering estimate. As discussed in Decision Report 69-8 wherein the Board adopted an SORW of 0.30 for Wizard Lake, the in-place reserve was not considered known with sufficient precision to justify at that time a more precise determination of flushing efficiency. It may be noteworthy, however, that in 1973, the Board, as a result of a multi-pool reserve review, recognized an SORW of 0.25 as being a representative average for a broad mix of high quality, high relief D-3 pools.

After review of the specific information available for the Wizard Lake D-3A Pool, the Board concludes that SORW very likely is in the range of 0.25 to 0.30. While this is somewhat less than the minimum SORW of 0.30 proposed by Texaco, the Board believes that excellent capillary quality and field demonstrated performance tend to support a lower SORW than that currently recognized by the Board. The Board agrees wholeheartedly with the Texaco plan for additional laboratory tests, special logging programs and performance reviews in the near term to provide a better indication of the SORW for this reservoir. For the purpose of the incremental tertiary reserve determination the Board has decided to adopt a median SORW of 0.28 pore volume. Further studies in the future may assist in better defining the SORW for the Pool.

## 3.4 Recovery Factor

### 3.4.1 Views of Texaco

Texaco calculated that it would achieve a recovery factor of 98.8 per cent by continuing to apply miscible flooding to a depth of 1205.5 mss based on performance achieved up to now. In its determination of tertiary recovery in the interval 1205.5 - 1229.6 mss, Texaco assumed that the interior (bell-shaped region of Figure 1 - (B)) of the reef would be completely resaturated to initial oil conditions and that 80 per cent of the flank areas would be resaturated. Texaco then assumed that the resaturated regions in the interval 1205.5 - 1228.1 would be miscibly flooded to a recovery of 98 per cent.

A 1.5 metre "sandwich" loss (1228.1 - 1229.6 mss) was employed in Texaco's recovery determinations. Although Board Decision Report 69-8 adopted a "sandwich" loss of 3 metres, Texaco referred to other D-3 reservoirs such as the Leduc Woodbend D-3A Pool to demonstrate that a "sandwich" loss of 1.5 metres could be achieved.

### 3.4.2 Views of the Board

The Board agrees with Texaco that the miscible flood performance has clearly demonstrated that a very high level of recovery is being achieved. Moreover, in view of demonstrated near 100 per cent recovery performance to date there is no longer a basis to differentiate between conformance efficiency and SORM effects in this pool even though both would be expected to be present to some degree. The Board thus adopts a miscible recovery factor of 98 per cent which is very close to that submitted by Texaco.

In determining the incremental recoverable reserves for the reflushed zone, the Board has assumed the interior region will achieve 95 per cent oil resaturation and that the flank region will experience 80 per cent oil resaturation. Accepting the interpreted high quality of the reflushed zone, the Board has adopted the recovery efficiency of 98 per cent for resaturated regions. Additionally, although it is reasonable to expect solvent bank coning effects and a need for artificial lift when the terminal sandwich is being depleted, the Board at this time accepts Texaco's proposed "sandwich" loss of 1.5 metres, subject to the reporting requirements outlined in Section 5.2 of this report.

## 3.5 Established Reserves

### 3.5.1 Views of Texaco

Based on the 98.8 per cent recovery in the secondary miscible flood and the cumulative production to year-end 1982, Texaco calculated primary/secondary miscible flood recovery to be 55 010 $10^3 m^3$. Incremental recovery from the reflush zone was determined to be 4 530 $10^3 m^3$. Accordingly, Texaco proposed that the pool recoverable reserves be adjusted upward to 59 540 $10^3 m^3$ when its scheme is implemented.

### 3.5.2 Views of the Board

Based on 98 per cent recovery for the existing miscible flood, the Board calculates reserves of 54 900 $10^3m^3$. Incremental recovery from the reflush region is estimated by the Board to be 4 080 $10^3m^3$ thus yielding a pool total reserve of 59 000 $10^3m^3$. The Board proposes to recognize these reserves effective 1 November 1983.

## 4. SCHEME DESIGN

### 4.1 Solvent Bank Composition

#### 4.1.1 Views of Texaco

Texaco conducted slim tube displacement tests and window cell PVT tests in an effort to determine the phase behavior and miscibility aspects of the existing solvent bank and that of the proposed addition. This study confirmed that the current solvent bank is first-contact miscible and that the combined solvent bank will continue to be first-contact miscible at the test pressure of 14 850 kPa(ga).

#### 4.1.2 Views of the Board

The Board observes that the proposed solvent is propane-rich in year 1 and ethane-rich in years 2 and 3, whereas the current solvent bank has much more butanes content. Hence, the Board is satisfied that the proposed cumulative solvent bank, after the tertiary addition, will remain first-contact miscible. Accordingly, cumulative solvent bank composition of 76.5 mole per cent ethane-plus enrichment, as proposed by Texaco, is considered appropriate at the existing minimum pressure of 14 480 kPa(ga).

### 4.2 Solvent Bank Size

#### 4.2.1 Views of Texaco

Texaco proposed the addition of some 1 825 $10^3Rm^3$ of solvent to the 4 275 $10^3Rm^3$ currently approved for the existing scheme, thus yielding a total solvent bank size of 6 100 $10^3Rm^3$. This value represents some 7.5 per cent of the hydrocarbon pore volume. Texaco stated that the currently applied-for solvent bank design incorporates more accurate diffusion and dispersion data than the original design as it is based on a fluid system which more closely approximates the actual reservoir fluid system. In addition, the current study permitted the gradual injection of the solvent bank. The overall solvent bank design incorporated a safety factor of 5 per cent in the C2-C4 hydrocarbon concentration.

#### 4.2.2 Views of the Board

The Board notes the improvement in the solvent bank design from the 1968 study in that it incorporates actual composition and coefficients of the reservoir fluids and more accurately reflects injection schedules. The Board also is satisfied that increasing the solvent bank to 6 100 $10^3Rm^3$ as proposed by Texaco should provide sufficient solvent for the scheme to operate successfully through to completion.

### 4.3 Contact Movement

#### 4.3.1 Views of Texaco

Texaco identified a need for a slow rate of downward movement in the O/W contact to achieve complete reflush reversibility. Texaco proposed to lower the O/W contact at an average controlled rate of 2 metres per year. Texaco also proposed a maximum fall of 3 metres in any given year to allow for flexibility in operating the project.

#### 4.3.2 Views of the Board

The Board agrees with the careful measures to control the rate of fall as proposed by Texaco and is satisfied that the rate is not too rapid in relation to the desired objective of essentially complete oil resaturation.

### 4.4 Solvent Spreading

#### 4.4.1 Views of Texaco

Texaco stated that solvent spreading is a function of injection rate while injection is occurring and of bank thickness when injection is terminated. The relatively high solvent injection rates provide a dynamic driving force while the bank thickness provides a horizontal spreading force due to density and gravity effects. Texaco believed that the proposed injection rates and the existence of a 10 metre thick bank already in place will provide an adequate driving force for the solvent to be spread to the reef flanks.

#### 4.4.2 Views of the Board

The Board does have some concern with respect to solvent spreading to the flank areas of the reservoir and believes that drilling of the proposed flank wells will be necessary to ensure proper resaturation, solvent spreading and effective miscible recovery in those regions. To monitor the adequacy of oil and solvent spreading to the flanks, the Board will require careful surveillance of the production characteristics of all future wells producing from the flanks.

## 5. MONITORING

### 5.1 Views of Texaco

In addition to the previously discussed special studies, Texaco will be undertaking to investigate SORW, porosity and oil resaturation, and report in accordance with the normal requirements under section 12.130 of the Oil and Gas Conservation Regulations. Texaco proposed the following special monitoring procedures:

- o reservoir pressure surveys at 3 wells in February, 6 wells in May, 3 wells in August and 6 wells in November of each year;
- o contact surveys at 6 wells to be run in May, August and November of each year to determine the gas-solvent, solvent-oil and oil-water contacts;
- o solvent and push gas compositions to be monitored on a monthly basis;
- o a monitoring procedure at production wells to detect solvent coning; and
- o for oil wells producing solvent, samples will be obtained three times per year to establish the degree of solvent production.

### 5.2 Views of the Board

The monitoring program proposed by Texaco is sound and consistent with the normal requirements of the Board. To ensure a thorough engineering synthesis of the results the Board will require the following special reports:

- o A report by no later than 1 January 1985 describing data and key results of the well deepening and subsequent logging/coring programs. This report should address matters such as SORW, porosity (core/log relationship) and general reservoir characteristics at the reef base.
- o For the year 1985 and thereafter, annual progress reports discussing available information with respect to the adequacy of oil and solvent spreading in the reef flanks.
- o A report in January 1987 describing data and key results of the flank-well drilling program and review of operating performance for all producing wells in relation to coning effects and ability to achieve a terminal "sandwich" of 1.5 metre oil pay.

## 6. DECISION

The Board grants the application and will issue Approval No. 3990, superseding Approval No. 1950, reflecting the terms and conditions cited in this decision report.

DATED at Calgary, Alberta on 28 September 1983

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy, P.Eng.
Board Member

N. Strom, P.Eng.
Board Member

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta



PETRO-CANADA INC.
SOUR GAS PIPELINE
FUEL GAS PIPELINE
BENJAMIN FIELD

Decision D 83-25
Applications 830736 and 830737

# 1 INTRODUCTION

## 1.1 The Applications

Petro-Canada Inc. (Petro-Canada) applied, pursuant to Part 4 of the Pipeline Act for permits to construct pipelines to gather sour gas from and deliver fuel gas to wells in the Benjamin Field. The sour gas would be processed at the Shell Canada Resources Limited Burnt Timber gas plant. The figure shows the proposed pipeline routes, the plant, and certain geographic and other features of the area.

Application 830736 is for a permit to construct approximately 23.8 kilometres (km) of 88.9- and 168.3-millimetre (mm) outside diameter (OD) sour gas pipeline from wells located in legal subdivision 11, section 33, township 28, range 7, west of the 5th meridian, 11-5-29-7 W5M, and 6-8-29-7 W5M to the gas plant located at 10-13-30-7 W5M.

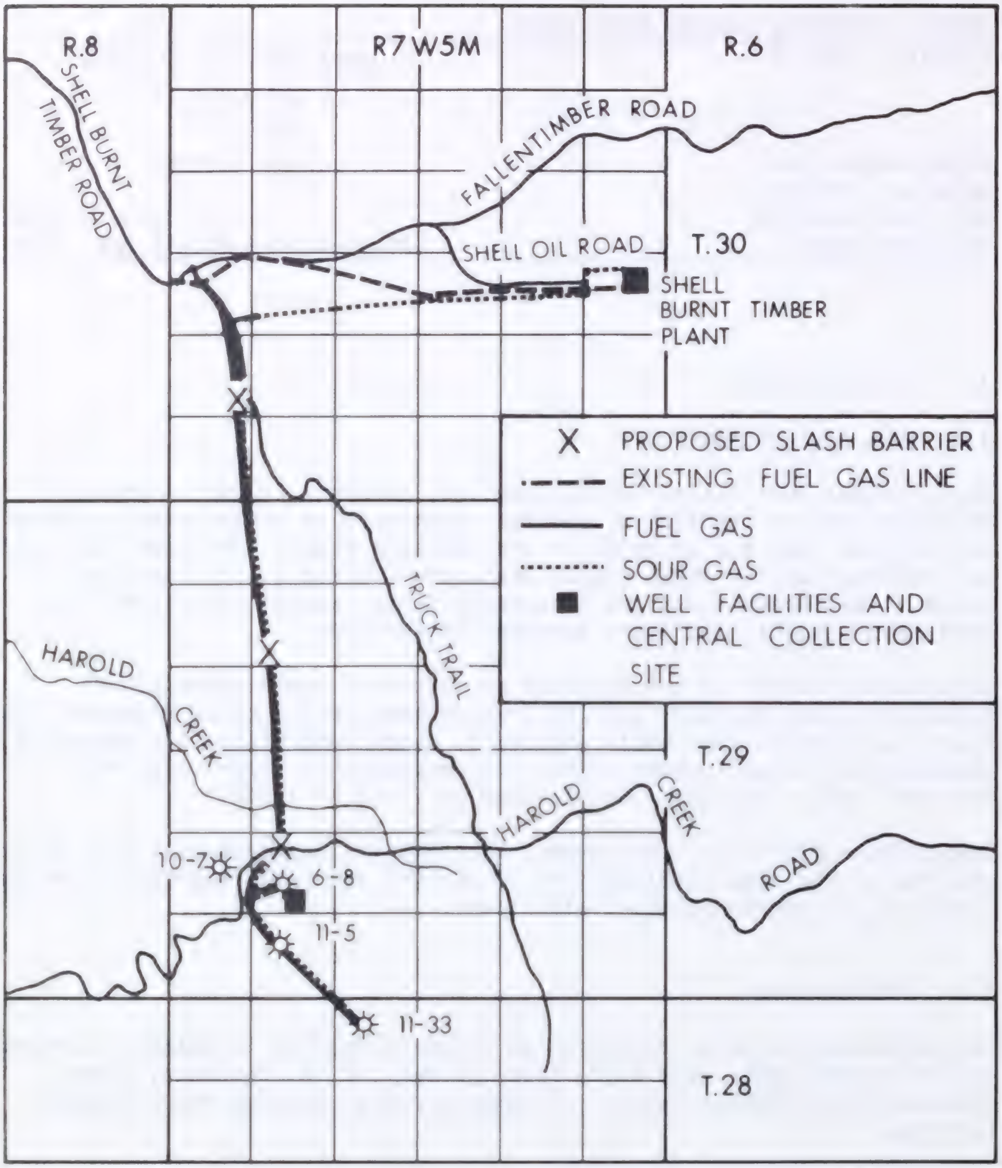
Application 830737 is for a permit to construct approximately 17.1 km of 60.3-mm OD fuel gas pipeline from 11-18-30-7 W5M (existing Shell fuel gas line) to the aforementioned well sites.

## 1.2 The Hearing

The applications were considered at a public hearing in Calgary, Alberta on 18 October 1983, with V. E. Bohme, P.Eng., E. R. Brushett, P.Eng. (Acting Board Member), and H. J. Webber, P.Eng. (Acting Board Member), sitting.

THOSE WHO APPEARED AT THE HEARING

| Principals and Representatives (Abbreviations used in Report) | Witnesses |
|---|---|
| Petro-Canada Inc. (Petro-Canada)<br>J. W. Gallagher | J. R. Pawson, C.E.T.<br>D. F. Mutrie, of Mutrie-Wishart Environmental Consultants |




PETRO-CANADA INC.
APPLICATIONS NO. 830736 & 830737
PROPOSED SOUR GAS GATHERING SYSTEM
DECISION D 83-25

THOSE WHO APPEARED AT THE HEARING (continued)

| Principals and Representatives (Abbreviations used in Report) | Witnesses |
|---|---|
| Canterra Energy Ltd. (Canterra)<br>C. H. Morel | |
| PanCanadian Petroleum Limited (PanCanadian)<br>B. W. Jones | |
| Shell Canada Resources Limited (Shell)<br>A.P.G. Walker | |
| Alberta Wilderness Association (AWA)<br>C. Bradley<br>V. M. Pharis | C. Bradley<br>V. M. Pharis |
| Her Majesty the Queen in the Right of the Province of Alberta (Crown)<br>T. Bossenberry | |
| Energy Resources Conservation Board staff<br>K. F. Miller<br>J. D. Dilay, P.Eng.<br>H. W. Knox, P.Eng. | |

At the conclusion of the hearing the Board approved the applications. This report outlines the reasons for its decision.

### 1.3 Preliminary Matters

At the beginning of the hearing, Petro-Canada challenged the status of the Alberta Wilderness Association (AWA) as local interveners. In its argument it cited three Board documents regarding local intervener cost matters: Guide G-31 Guidelines Respecting Applications For Local Interveners' Costs Awards, Decision D 83-8 Local Interveners' Costs Hearings Respecting the Jumping Gas Processing Plant, the Quirk Creek Gas Processing Plant, and the Proposed Moose and Whiskey Fields Pipeline Hearings, and Decision D 83-9 Local Interveners' Costs Hearings Respecting the Ram River Gas Processing Plant and the Strachan Gas Processing Plant Hearings. While Petro-Canada submitted that the AWA did not qualify for interveners' costs under the criteria established by the Board as set out in the decision reports, it did not question the AWA's right to make representations at the hearing.

The Board noted Petro-Canada's argument and ruled that it would decide the AWA's status as a local intervener if and when the AWA made an application for costs respecting the hearing.

## 2 ISSUES

The Board considers the issues to be:

- o need for the proposed pipelines
- o pipeline right of way access

## 3 NEED

Petro-Canada said the proposed pipelines were needed to gather sour gas from the 11-33, 11-5, and 6-8 wells for processing at the Shell Burnt Timber gas plant and to deliver fuel gas to the wells. It stated that the processing of Benjamin Field gas at the Shell plant was not yet approved but noted that Shell had applied to the Board for the necessary approval. Petro-Canada said that its gas was contracted to Pan-Alberta Gas Ltd. and that the pipeline was designed to accommodate future PanCanadian Petroleum Limited (PanCanadian) production from the 10-7-29-7 W5M well.

None of the interveners questioned the need for the proposed pipelines.

The Board notes Petro-Canada and PanCanadian have sales gas contracts for the Benjamin Field gas and it is satisfied that need for the proposed pipelines exists provided Shell's application for processing Benjamin Field gas at its Burnt Timber plant is approved. The Board will condition any permits issued for the proposed pipelines to be subject to Board approval of the processing of Benjamin Field gas at the Shell plant.

## 4 PIPELINE RIGHT OF WAY ACCESS

### 4.1 Petro-Canada's Views

Petro-Canada stated that the land which the pipeline would cross is zoned for Multiple Use (Zone 5) under ... "the jurisdiction of "A Policy for Resource Management of the Eastern Slopes" (Alberta Energy and Natural Resources, 1977a)." and access to the right of way is by the Fallentimber and the Shell Burnt Timber roads to the north and via the Harold Creek road to the south (see figure). Off-highway vehicles could also gain access to the proposed right of way by the "Truck Trail" (see figure) and by several southwest to northeast oriented seismic cutlines across the area. It stated that while small local areas might be considered wildlands, it believed that because of the ease of access and the various land uses allowed, the general area should not be considered as wildlands.

Petro-Canada proposed to dogleg the pipeline right of way to reduce its visibility at the crossing of the Harold Creek Road and where the

pipeline joins the Truck Trail. For erosion control purposes it proposed to discourage access onto the right of way by placing 200-metre long slash barriers at each dogleg and one at the end of a muskeg area north of Harold Creek (see figure). The slash barriers would be created by "walking" unmerchantable timber into the right of way soil with a bulldozer. Concerning the AWA's request not to "walk" unmerchantable timber at the slash barriers Petro-Canada contended that without compaction a fire hazard would result, right of way rehabilitation would proceed more slowly and, from an operational viewpoint, emergency access would be significantly more difficult.

Regarding the control of seismic cutline access, Petro-Canada stated that, while it did not propose any additional slash barriers at this time, it would discuss these matters further with the Alberta Forest Service (AFS).

Petro-Canada agreed with AWA's request not to install gates on the drift fences separating area grazing allotments on the right of way, but with respect to AWA's further requests stated that it was unable to provide additional informational signing, physical barriers, and locked gates where the pipeline intersects with public roads because "it is not within our power to do any of these points."

### 4.2 AWA Views

The AWA stated that the lands to be crossed by the pipeline are "de facto wildlands" and that vehicular access should be restricted. While it supported Petro-Canada's access-control proposals to dogleg the right of way and provide slash barriers, it also requested further measures. These consisted of not "walking" the slash barriers (which it contended would result in a more effective barrier to vehicular traffic), not gating drift fences on the pipeline right of way, and placing slash at seismic cutline/right of way crossings. The AWA also requested the Board to ask AFS to ensure that motorized access onto the right of way be made illegal and that informative signs, physical barriers, and locked gates be placed where the pipeline crosses the Harold Creek Road and where it joins the Truck Trail.

### 4.3 Board Views

The Board notes the access-control measures proposed by Petro-Canada (doglegs and slash barriers) and that the AWA is in substantial agreement with those measures. The Board believes that vehicular access to the right of way will be substantially eliminated by the measures proposed by Petro-Canada, especially if it obtains agreement from AFS to limit access where the seismic cutlines intersect the right of way.

Concerning the AWA's request that the Board ask AFS to make access illegal and provide signs, physical barriers, and locked gates, the Board believes these matters to be clearly within the jurisdiction of the Alberta Department of Energy and Natural Resources (AENR). It also believes that since the AWA can quite adequately present its views through direct access to AENR, it should not intervene in a policy matter which is clearly the particular mandate of that Department.

## 5 DECISION

The Board grants Applications 830736 and 830737 by Petro-Canada Inc., subject to:

(1) approval of the processing of the Benjamin Field gas at the Shell Burnt Timber plant, and

(2) approval of the Minister of the Environment respecting environmental matters.

ISSUED at Calgary, Alberta on 31 October 1983.

ENERGY RESOURCES CONSERVATION BOARD

V. E. Bohme, P.Eng.
Board Member

E. R. Brushett, P.Eng.
Acting Board Member

H. J. Webber, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

HOME OIL COMPANY LIMITED
HYDROCARBON MISCIBLE FLOOD
SWAN HILLS BEAVERHILL LAKE A & B POOL — Decision D 83-26
UNIT NO. 1 — Application 830674

# 1 INTRODUCTION

## 1.1 Application and Hearing

Home Oil Company Limited (Home) applied, pursuant to section 26 of the Oil and Gas Conservation Act, to implement a hydrocarbon miscible flood scheme in part of Unit No. 1 of the Swan Hills Beaverhill Lake (BHL) A & B Pool. Home expected to drill 32 infill wells in 1984 and begin solvent injection by mid 1985. Home estimated the scheme would recover as much as 0.15 ($10.7 \times 10^6 m^3$) of the initial A Pool project oil in place (OOIP) in addition to that which would be recovered by the existing waterflood. The proposed scheme would involve the injection of solvent and push gas volumes of 0.15 and 0.30 of hydrocarbon pore volume (HCPV) of the pattern area, respectively, or a total of $12.9 \times 10^6 m^3$ and $25.8 \times 10^6 m^3$ at reservoir conditions. Solvent enrichment would be sufficient to achieve first contact miscible displacement. Both the solvent and push gas would be injected alternately with water at a target water-alternating-gas (WAG) ratio of 1.0.

The application was heard by the Energy Resources Conservation Board in Calgary, Alberta, on 18 October 1983 with G.J. DeSorcy, P.Eng., N. Strom, P.Eng., and F.J. Mink, P.Eng., sitting.

## 1.2 Appearances

Those who appeared at the hearing are listed in the following table.

TABLE 1 THOSE WHO APPEARED AT THE HEARING

| Principals and Representatives (Abbreviations used in Report) | Witnesses |
|---|---|
| Home Oil Company Limited (Home)<br>R. M. Perrin | R. C. Osborne<br>D. F. Botterhill, P.Eng.<br>W. B. Baker, P.Eng.<br>M. L. Johns, P.Eng.<br>W. M. P. B. Koster, P.Eng. |
| Amoco Canada Petroleum Company Limited (Amoco)<br>M. J. Miners | |
| Esso Resources Canada Limited (Esso)<br>J. E. Lowman | |
| Gulf Canada Resources Inc. (Gulf)<br>T. E. Randall, P.Eng. | |
| Texaco Canada Resources Ltd. (Texaco)<br>W. Muscoby | |
| Energy Resources Conservation Board staff<br>R. J. Willard, P.Eng.<br>D. N. Bouclin, P.Eng. | |

The Board received four submissions requesting the right to intervene for the purpose of cross-examination only. In closing statements Gulf, Amoco, and Texaco expressed support for the application.

## 2 BACKGROUND

The Swan Hills Beaverhill Lake A & B Pool is located in north central Alberta and was discovered in 1957. Swan Hills Unit No. 1 constitutes a major portion of the Swan Hills BHL A & B Pool (Figure 1). The principal producing formations are a large carbonate bioherm (A Pool) built up over a comparatively dense limestone reef platform (B Pool) (see Figure 2).

At discovery, the A & B Pool was highly undersaturated with an initial pressure of 22 790 kilopascals (kPa) compared to a bubble point pressure of 12 436 kPa. Early performance of the pool indicated that the primary depletion mechanism was an inefficient expansion and solution gas drive. After unitization in 1963, a line drive waterflood pressure maintenance scheme was initiated in the western portion of the reef buildup area. As the rate of pool production increased the waterflood was expanded to the remainder of the unit by means of a partial pattern waterflood. In 1978, a program of infill drilling to 32 hectares (ha) spacing was initiated in selected quarter sections in an attempt to recover oil reserves believed trapped or inaccessible by the then existing well configurations. The Swan Hills Unit No. 1 contains an A Pool OOIP of 216 x $10^6 m^3$ and is currently producing at an average daily oil rate of 6 600 $m^3$ and an average water oil ratio of 2.2 $m^3/m^3$. The cumulative oil recovery to 31 December 1982 is 65 x $10^6 m^3$ or 0.30 of the A Pool OOIP.

Home pointed out that future oil production from the B Pool within the proposed project area would be negligible and, as such, the later pool was excluded from Home's evaluation of miscible flood performance. For correct comparison the Board has also based its estimate of incremental recovery on the oil in place for the A Pool. However, for subsequent reserves accounting, the incremental recovery must be adjusted to reflect the combined A & B OOIP.

## 3 ISSUES

The Board believes that the main issues for consideration in this application are the:

- o Desirability of the project in the public interest
- o Incremental recovery
- o Design features and special conditions
- o Need for infill drilling

## 4 THE DESIRABILITY OF THE PROJECT IN THE PUBLIC INTEREST

### 4.1 Views of the Applicant

Home put forward several positive effects that a miscible flood project would have on Alberta, from both an economic and conservation point of view. It said that the recovery of some 10.7 x $10^6 m^3$ of incremental crude oil would benefit Canada by increasing the domestic crude oil supply and contributing to self sufficiency. Home indicated that the present value of net revenue from its project (at a 10 per cent discount rate) is some $800 million for the period 1985 to 2016, a value to be shared by the industry and the government. The project yields a rate of return of some 25 per cent

excluding the benefit that may be derived from the production of gas and gas liquids used by the scheme. The project would also require a large infill well drilling program which would provide increased employment opportunity for the operation, supply, and service portions of the drilling industry. Home reported that the incremental capital investment required to implement the project amounted to some $90 million. Also, the implementation and monitoring of the hydrocarbon miscible flood in Swan Hills Unit No. 1 would increase the Province's enhanced oil recovery technology base and provide experience for future miscible floods in all areas of Canada.

Home commented that its plan to miscibly flood only a portion of Unit No. 1 as an initial stage had regard for:

- the need to limit investment,
- the reduced volumes of natural gas and natural gas liquids (NGL) required for the project would be easier to secure, and
- the smaller scale of initial operation would limit the risk by permitting performance monitoring and performance assessment useful to the design of full-scale operation in future.

Provided favourable performance and economics were available, Home anticipated a possible expansion of the scheme by 1990. Such an extension would permit recycling of the breakthrough solvent derived from the initial scheme. Home was not aware of any significant supply and demand problems for NGL in the early 1990s. Further, Home believed that the delay in implementing full-scale miscible flood operations would not impact negatively on ultimate recovery.

### 4.2 Views of the Board

The Board is satisfied that the proposed scheme is in the public interest considering:

- It has the potential to increase Canada's oil supply.
- It increases the long-term cash flow for the industry and provides additional revenue to the government.
- It provides a relatively efficient and timely use of the current surplus of sales gas and natural gas liquids.
- It would foster significant economic benefits to Alberta through increased activity and taxes.
- It promotes sound resource management and utilization relative to industrial development and upgrading.

The Board agrees with Home that the A member of Swan Hills Unit No. 1 is a good technical candidate for miscible flooding. Also considering the relatively advanced stage of the existing waterflood, the Board believes that a unit-wide flood would have to be implemented in a practical, expeditious manner in order to ensure success. Specifically, the Board believes that the current regime of prices, royalty relief, and favourable gas supplies, when considered along with declining oil productivity and increasing water cuts in Unit No. 1, suggests that an agressive implementation schedule would have particular advantages. Also from the perspective of natural gas and NGL supply and demand, the Board believes that a window of opportunity will exist throughout the late 1980s which may not be available thereafter.

# 5 INCREMENTAL RECOVERY

## 5.1 Views of the Applicant

### 5.1.1 Overview of Anticipated Incremental Recovery

Home investigated miscible flood incremental recovery and performance for the patterns of the A Pool as shown in Figure 1, which encompasses an area of 4096 ha (pattern area). However, a project area, which includes full spacing units for all patterns, would be 4608 ha.

Home estimated the average pattern incremental recovery factor for the miscible flood to range from 0.14 to 0.17 of the OOIP in the pattern area resulting, as shown in Table 2, in incremental recoverable reserves ranging from 8.8 to 10.7 x $10^6 m^3$. This is equivalent to an average incremental recovery for the project area of 0.125 to 0.152.

TABLE 2 Incremental Recovery of Hydrocarbon Miscible Flood

| | A Pool OOIP ($10^6 m^3$) | Area (ha) | Incremental Recovery Factor (f) | Incremental Recoverable Reserves ($10^6 m^3$) |
|---|---|---|---|---|
| Interior | 33.4 | | 0.166 to 0.193 | 5.5 to 6.5 |
| Rim | 29.4 | | 0.111 to 0.141 | 3.3 to 4.2 |
| PATTERN TOTAL | 62.8 | 4096 | 0.140 to 0.170 | 8.8 to 10.7 |
| PROJECT TOTAL | 70.4 | 4608 | 0.125 to 0.152 | 8.8 to 10.7 |

As shown in Table 3, Home's estimate of the incremental tertiary flood recovery was based on a number of modifiers designed to reflect the associated changes in recovery as the pool is transformed from a waterflood to miscible flood. Using a displacement efficiency based on waterflood residual oil saturations (Sorw) and the projected waterflood recoveries by decline curve analysis, Home calculated the total waterflood volumetric sweep efficiency. As calculated, the latter includes the effects of areal and vertical sweep, conformance, and continuity. The total waterflood volumetric sweep efficiency was converted into an equivalent solvent flood sweep efficiency by applying two modifiers, designed to reflect the effects of adverse mobility, improved pattern geometry, and drilling of infill wells. The resulting solvent flood volumetric sweep efficiency was subsequently used in conjunction with the solvent displacement efficiency to generate the incremental tertiary recoveries in both the rim and interior area.

Specifically, Home's estimate of incremental tertiary recovery reflected several factors as outlined below and summarized in columns 1 and 2 of Table 3.

### 5.1.2 Residual Oil Saturations

Home estimated Sorw to be 0.27 in the reef rim and 0.30 in the reef interior. Home stated that these values were determined judgementally after consideration of pressure cores, a log-inject-log program, and material balance calculations resulting from the 1978 Waterflood Engineering Study. This study, which Home believed gave the most reliable data, showed an Sorw of 0.25 in upper zones A to C and Sorw of 0.45 in the D zone. Home explained that the D zone had lower porosity and smaller pore spaces. This would cause substantially increased capillary pressures and consequently higher residual oil saturation. Home stated that the range of Sorw could be from 0.25 to 0.35 for the whole project area.

Home assumed miscible flood residual oil saturations (Sorm) to be 0.05 of pore volume. This was substantiated by a stacked core flood test which showed a recovery factor of 0.95.

### 5.1.3 Project Waterflood Recovery Factors

Home used a waterflood performance from the whole of Unit No. 1 as a basis for estimating waterflood recoveries (reef rim and reef interior). Home believed that the expected waterflood[1] recovery for the entire Unit No. 1 would be 86 x $10^6 m^3$ or 0.40 of the A Pool OOIP. Home stated that the waterflood recovery predicted from the 1978 Waterflood Engineering Study was still valid since actual production performance since 1978 had generally matched the forecast. However, oil migration within Unit No. 1 has been

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1 Waterflood also includes primary production of 0.018 which preceded commencement of waterflooding.

prevalent for many years rendering, in Home's opinion, any evaluation of waterflood performance on an area by area basis difficult.

By analogy to unit-wide performance, Home estimated waterflood recovery factors for the proposed project area based on assigned recoveries of 0.38 for the project reef interior and 0.48 for the project reef rim. The overall average would be 0.43 considering that the rim and interior each contribute about half of the project OOIP. The results of Home's extrapolation of unit waterflood performance to the pattern area generated a volumetric sweep in the interior and rim areas of 0.60 and 0.715, respectively.

5.1.4 The Reservoir Simulation Study

A reservoir simulation study was conducted to evaluate several design features and to investigate the tertiary recovery potential of Swan Hills Unit No. 1. Two small study areas were selected representing reef rim and reef interior areas. A three-dimensional three-phase black oil model was utilized to obtain a pressure history match and to generate waterflood performance predictions. The miscible flood forecasts were generated using a four-phase model to simulate the complex solvent-oil movements in the miscible flood. The pressure history match was obtained by inflating production. The model assumed pseudo-immiscible slipping (viscous fingering) of the solvent past the oil to represent the unstable interface of the solvent-oil bank. The interior model used five single-cell layers with no cross-flow, while the rim model used six layers and permitted cross-flow between principal layers.

The reservoir simulation study showed the incremental oil recovery in the pattern area was in the range of 0.12 to 0.161 of the OOIP for the reef interior area and 0.075 of the OOIP for the reef rim area. Home believed that the incremental tertiary flood recoveries for the model areas were rendered low because the waterflood recoveries obtained from the simulation study were abnormally high, in the order of 0.52 to 0.55 of the OOIP. Home noted the expected waterflood recovery for the project is 0.43 of the OOIP so that much more oil should be available for miscible flooding. In addition, Home commented that the rather low recovery for the reef rim model was attributed to gravity override. In summary, Home was of the opinion that the simulator model predicted lower incremental recoveries under miscible flooding than would actually be expected in the field.

5.1.5 Gravity Override

In estimating incremental recovery, Home did not account for any detrimental effects of gravity. Home pointed out that in the reef rim portion of its applied-for project there are thin tight stringers which would dampen the effects of gravity override. Also, the reef interior portion is

generally characterized by discontinuous porous lenses with limited vertical communication which would negate the possibility of gravity override.

#### 5.1.6 Sweep Efficiency Modifiers

Utilizing the interpretive existing waterflood volumetric sweep as a reference, Home applied a number of modifiers to estimate the change in total sweep efficiency due to more adverse miscible fluid mobility, improvements in pattern design, and infill drilling benefits.

A mobility modifier of 0.88, derived from the Reservoir Simulation Study, was used to quantify the relative reduction in the volumetric sweep efficiency as a result of mobility differences.

A pattern design modifier was used to reflect the benefits derived from the infill drilling program and well conversions. Home believed there would be an improvement in sweep efficiency resulting from having more complete symmetric patterns and removal of windows of unswept or partially swept oil that currently exists under waterflood operations. Home realized it was difficult to quantify the effects of these two factors but estimated a modifier effect ranging up to 1.05. This pattern design modifier was applied to both the rim and interior portions.

An infill drilling modifier of 1.1 was applied to the reef interior to incorporate the effects of the proposed 32 infill wells. In the 1978 Waterflood Engineering Study, the OOIP in part of the reef interior had to be reduced by 0.312 to obtain a history match of performance. However, by infill drilling, the total sweep efficiency would be increased by contacting part of this inaccessible oil in place. Home anticipated that one-third of this inaccessible oil in place or about 0.10 of OOIP would become accessible. Thus an infill drilling modifier of 1.1 should be applied to the reef interior. This equates to an increase in "captured" oil of about 57 000 $m^3$/well.

By applying the above modifiers to the waterflood factors, Home calculated a maximum incremental recovery of 0.17 of A Pool OOIP for the pattern area or 0.152 of the A Pool OOIP for the project area. The results are summarized in Table 3.

### 5.2 Views of the Board

#### 5.2.1 Residual Oil Saturations

The Board has reviewed the different sources of information on Sorw; conventional water-base cores, preserved cores, coreflood tests and, log-inject-log field tests. The Board is of the view that coreflood tests are susceptible to error due to the wettability of the core being altered during core preparation. As well many of the coreflood tests are conducted with stock tank oil rather than reservoir oil, which can introduce different interfacial tension and mobility effects than would be the case in the

reservoir. For pressure core, mud invasion can reduce the confidence level of the measured oil saturation. For the log-inject-log program there are some interpretational problems. In spite of the shortcomings of any one method, however, the Board is satisfied that the compendium of information from residual saturation evaluation methods, when incorporated with waterflood performance analysis, rather strongly supports Home's estimate that the Sorw for the Swan Hills Beaverhill Lake A & B Pool is approximately 0.30. In addition, the Board agrees that the residual oil saturation for solvent flood would be 0.05.

#### 5.2.2 Project Waterflood Recovery

The Board agrees with Home's estimated unit-wide waterflood recovery factor of 0.40 based on the A Pool OOIP. The Board has also adopted Home's values for project OOIP and pattern OOIP as given in Table 2.

The Board recognizes that the contrast in reservoir rock types of the reef interior and reef rim areas may contribute to different waterflood performance. However, due to oil migration between these different areas, production data would not be quite conclusive to verify the 10 per cent waterflood performance variance proposed by Home. In any case, the Board agrees that the performance in the application area warrants a higher recovery factor than the unit average of 0.40 and has decided to adopt a waterflood recovery factor of 0.42 for the subject area.

In addition, the Board believes that further definitive study with regard to oil migration, performance analysis, and identification of remaining recoverable reserves on project rim and interior areas respectively (even on individual pattern basis if possible), is crucial in fulfilling future monitoring and performance assessment requirements.

#### 5.2.3 The Reservoir Simulation Study

The Board finds that no allowance was made for reservoir discontinuities in the modelled areas and, as a consequence, the models predicted higher waterflood recoveries than indicated by pool performance. In the referenced model studies, a reasonable history match was obtained only after substantial adjustments to the input production data. With the scale of adjustment to the production data ranging from 1.3 in the reef interior model to an average of 1.6 in the reef rim model, the predicted recoveries were in the order of 0.516 to 0.548 for the two models, respectively. When compared to a unit average of 0.40 projected by decline curve analysis, the model recoveries are rather high, suggesting the presence of some non-contributory pays in the pool. If properly accounted for in the model studies, these discontinuities would have reduced the need for substantial adjustment to the production data, resulting in more realistic waterflood recoveries. However, despite this limitation, the Board finds that the model results could be used to assess the incremental tertiary flood recoveries provided that appropriate modifications are made to compensate for reservoir discontinuity.

### 5.2.4 Incremental Tertiary Recovery

The Board is of the view that the incremental tertiary flood recoveries should be assessed considering:

- the volume of reservoir accessible to miscible flooding, ie, reservoir continuity,
- displaceable oil in the solvent contacted area, and
- volumetric sweep efficiency and gravity override.

#### 5.2.4.1 Reservoir Continuity

To provide a reliable estimate of reservoir continuity requires detailed geological and continuity model studies for the pool. In the absence of such studies, the Board finds it necessary to estimate reservoir continuity in some qualitative manner. Based on the projected waterflood recovery of 0.40 in the unit area and a residual oil saturation of 0.30 in the water flooded zones, material balance calculations indicate a continuity factor of about 0.85. In addition, a major waterflood study performed by Home in 1978 indicated that nearly 0.30 of the oil in the interior of the project area was not contributing to the performance of the unit, suggesting a continuity factor of about 0.70 in the interior. As a result, the Board concluded that the predicted waterflood recoveries by the models should be adjusted to reflect reservoir discontinuity as evidenced by pool performance. If the Board were to use Home's projected waterflood recoveries of 0.48 and 0.38 for the rim and interior areas, the model results suggest a continuity factor ranging from 0.74 in the interior to about 0.88 in the rim area, or an average pool continuity factor of nearly 0.80. As a result, the Board has adopted a continuity factor of 0.80 for the pool.

#### 5.2.4.2 Displaceable Oil

Accepting the residual oil saturations of 0.30 and 0.05 in the water and solvent contacted zones, the Board estimates that only 0.25 of the continuous pore volume would be available for tertiary oil recovery, representing a displaceable oil by solvent of nearly 0.30 of the initial oil in place.

#### 5.2.4.3 Volumetric Sweep Efficiency

In the reef interior model, the oil recoveries for the waterflood and miscible flood cases (Cases W1 and M1) were 435.83 and 571.57 x $10^3 m^3$, representing an incremental recovery by solvent of 135.74 x $10^3 m^3$. This incremental recovery over the waterflood case suggests that nearly 0.65 of the water swept zone would be contacted by solvent, resulting in a volumetric sweep of about 0.53 of pore volume. In contrast, the volumetric sweep for the reef rim model was too low, amounting to 0.25 of pore volume.

By comparison with its counterpart for the reef interior model, the latter suggests a relative gravity override factor[2] of about 0.47 which, if weighed volumetrically, translates to a pool average gravity override factor of 0.75.

5.2.4.4 Calculation of Incremental Recovery

Based on a reservoir continuity factor of a 0.80, a displaceable oil of 0.30, a volumetric sweep of 0.53, and a gravity override factor of 0.75, the incremental tertiary flood recovery amounts to 0.095 of the oil in the pattern area.

5.2.5 Recovery Modifier

5.2.5.1 Gravity Override

The Board notes that the indicated gravity override factor was influenced to some extent by the higher waterflood recoveries predicted by the reef rim model. Also adding significantly to the gravity override was the cross-flow permitted between the layers in the reef rim model. In addition, the Board recognizes that because of the discontinuous nature of porosity and the presence of tight stringers in the northwest rim area, gravity override would be less signficiant than indicated by the model. Having regard for the foregoing, the Board finds it appropriate to revise the relative gravity override for the rim area of 0.47 derived from the model to 0.70. This results in a pool average gravity override factor of about 0.85. As a result of the revised gravity override factors, the Board expects the incremental tertiary flood recovery to be 0.108 of A Pool pattern OOIP.

5.2.5.2 Infill Drilling

The Board agrees with Home that drilling of an additional 32 wells on 32-ha spacing is likely to improve both the continuity and the volumetric sweep in the interior area of the project. However, the Board is of the view that unless the wells are drilled on significantly smaller spacings than proposed by Home, the improvement in continuity is not likely to exceed 10 per cent. The Board expects that the proposed infill drilling by Home would result in a continuity factor of about 0.80 in the interior area of the project. With this improvement, an additional $4 \times 10^6 m^3$ of pore volume would be available for both water and solvent flooding, contributing $1.68 \times 10^6 m^3$ of oil or the equivalent of $52.5 \times 10^3 m^3$ per well. In terms of the oil in place in the pattern area, the latter represents an additional recovery of 0.027. In estimating the additional recovery resulting from infill drilling, the Board applied the same volumetric sweep efficiency data as derived from the reef interior model.

Aside from the improvement in continuity, infill drilling and conversion of wells is also likely to improve volumetric sweep in the pattern area. While it is very difficult to quantify the resulting improvement in the sweep, the

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2 The relative gravity override factor is defined as the ratio of the volumetric sweeps of the two models.

Board believes a volumetric sweep modifier of 1.025 is reasonable, resulting in an additional recovery of 0.01.

For illustration purposes, a summary of the data adopted by the Board and Home in determining the incremental recovery from the project is shown in Table 3.

### 5.3 Total Incremental Tertiary Flood Recovery

The Board expects the total incremental pattern tertiary flood recovery to be 0.145, of which 0.037 will arise from the benefits derived from infill drilling. This equates to a total incremental oil recovery of $9.1 \times 10^6 m^3$. When compared to the larger project OOIP, the total incremental recovery factor is 0.129.

## 6 DESIGN FEATURES AND SPECIAL CONDITIONS

### 6.1 Views of the Applicant

The important design features of the miscible scheme are outlined below.

#### 6.1.1 Design of Solvent Composition

Home's solvent composition was designed to have a minimum miscibility pressure of 17 237 kPa. The anticipated average operating reservoir pressure would range from 18 616 kPa to 19 995 kPa thereby ensuring a sufficient safety factor for the miscibility of the solvent. Home did not submit a single solvent composition, since it was currently negotiating with various gas and NGL suppliers and further expects the supply source compositon of ethane plus ($C_2$+) to vary with time. A computer program was developed to establish a solvent miscibility control technique. The computer program combines the characterized Swan Hills crude oil and a Benham-type pseudo tertiary diagram model to establish the $C_2$+ content of the solvent as a function of the composition distribution of the natural gas liquids for a given minimum miscibility pressure. The validity of the computer program was confirmed by laboratory phase experiments and slim tube tests.

Home estimated its "target" composition of injection solvent to have a $C_2$+ content of 86.5 mole per cent. Since the component distribution of the NGL supply will vary with time, Home's computer program will determine the ratio of NGL to dry gas necessary to maintain miscibility. For example, estimated NGL:dry gas ratios would vary from 59:41 to 70:30 for Mitswan and Elmworth NGL supply respectively.

#### 6.1.2 Bank Sizes and WAG Ratio

Home proposed to inject into each pattern a solvent bank volume equal to 0.15 of the hydrocarbon pore volume (HCPV) of each pattern area and a chase gas bank of 0.3 HCPV. In accordance with the WAG program,

injection of hydrocarbons would be alternated with water on approximately a two-month cycle. Although the targeted WAG is 1.0, it may range from 0.72 to 2.25 as dictated by operating constraints such as the disposal of excess produced water.

### 6.1.3 Injection and Production Strategy

Home planned to use 23 injectors to miscibly flood 21 patterns. The proposed patterns would require the drilling of 32 infill wells and the conversion of 13 existing producers to solvent injectors. Two of the existing water injectors at Lsd 10-18-67-10 and Lsd 4-28-67-10 do not conform to the proposed patterns and would be evaluated for their potential in the miscible project prior to commencement. The project area incorporates inverted 9-spot patterns on 32-ha spacing in the south and east areas and semi-inverted 9-spot patterns on 64-ha spacing in the north and west areas. Home planned to miscibly flood all patterns simultaneously. The solvent injection period is estimated to take 6 years from flood start and the push gas injection period requiring 12 years.

The proposed plant for manufacturing miscible fluids will be located adjacent to the existing compressor station in Lsd 3-8-67-10 W5M. The injection fluids will be distributed to five injection satellites throughout the project area. The injection satellites will allow any injector to be placed on either miscible fluid, push gas, or water injection. Water injection pumping will take place at the existing produced water pump station in Lsd 10-21-67-10 W5M.

### 6.1.4 Completion Strategy and Well Monitoring

Home outlined a selective completion strategy to maximize injection coverage and production from the six major producing horizons. The 32 infill wells are targeted for initial completion in poorer zones only. The rate of solvent breakthrough, solvent injectivity, and oil productivity would dictate when an individual producer should be completed in a more permeable zone. The 13 proposed solvent injectors which are currently producers would be assessed individually for an optimal zone completion. Recompletion of existing injectors to the poorer zones was not anticipated because past experience showed limited success due to the deterioration of the reservoir rock and cement in the vicinity of the wellbore.

Home realized the need for a comprehensive monitoring system for such parameters as bottom-hole pressures, injection and production volumes for each zone, and the composition of fluids injected and produced. The details of the monitoring program were not finalized but would be presented for ERCB approval prior to initiating solvent injection.

## 6.2 Views of the Board

The Board finds Home's plan to inject solvents of varying composition acceptable, provided it is always sufficiently rich to achieve first-contact miscibility at a pressure of 17 237 kPa.

The Board is satisfied that a solvent bank volume of 0.15 HCPV and a push gas bank of 0.3 HCPV for each pattern should be adequate to obtain the expected incremental recovery. In this respect the Board understands that continuity would render miscible flood pore volume somewhat less than calculated pore volume. The Board realizes that while the ideal target WAG ratio is 1.0, variations may occur due to operating constraints and accepts the range proposed by Home.

The Board accepts Home's choice of surface facilities and injection strategy. However, the Board has some concern about the capacity of the gas conservation facilities to handle any earlier than expected solvent breakthrough and expects Home to carefully monitor any such development and ensure that facilities are expanded in a timely fashion.

The Board considers Home's selective completion strategy as a sound attempt to effectively distribute miscible fluids to the different zones. This strategy should increase the total sweep efficiency and improve recoverable reserves.

# 7 THE NEED FOR INFILL DRILLING

## 7.1 Views of the Applicant

Home proposed to drill 32 infill wells on 32-ha spacing in the reef interior of the hydrocarbon miscible flood project. The objective of the infill drilling would be to achieve earlier miscible flood response and to improve miscible flood control.

The infill wells would result in improved continuity between wellbores, allow more pore volume to be miscibly flooded and improve the recovery of the miscible fluid injected. Home also submitted that infill drilling would improve control over the miscible flood by decreasing drift of the miscible fluid and reducing pressure gradients. It would further aid in flood monitoring and offer increased operational flexibility.

For these reasons, Home regarded the infill well program as an integral part of the miscible flood project. Considering the high cost of drilling and completing the additional wells (estimated at over $40 million), Home stated that full allowance of this incremental capital investment under section 4.2 of the Alberta Petroleum Royalty Regulations would be required in order for the project to be economically viable.

7.2 Views of the Board

The Board is satisfied that the infill program is very important to the overall success of the project and agrees with Home that in large part the program should be regarded as an integral part of the miscible flood project.

8 DECISION

8.1 The Board approves the scheme for enhancement of oil recovery by a hydrocarbon miscible flood for a portion of the Swan Hills Beaverhill Lake A & B Pool as submitted by Home. The terms and conditions of the approval will be essentially as shown in the attached Form of Approval.

8.2 The Board will require Home to submit a progress report respecting expansion to a Unit-wide miscible flood two years after commencing the scheme approved herein.

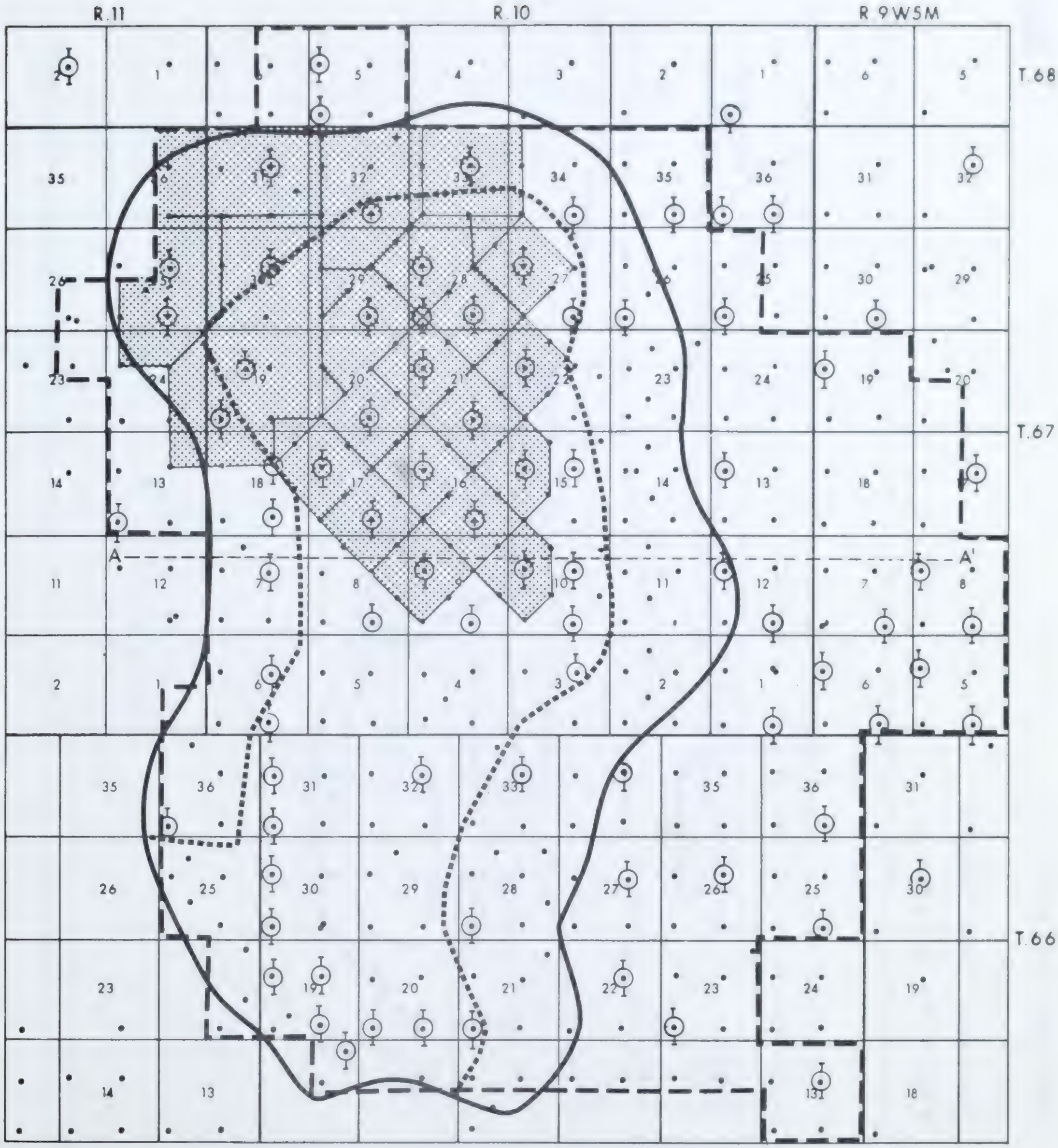
8.3 In order to properly monitor incremental recovery and general success of the miscible flood project, the Board will require Home to submit a report, by 1 January 1985 establishing flood-start reservoir properties for the project patterns. Among other things this will necessitate assessment of oil migration and identification of waterflood remaining recoverable reserves on a project and pattern basis.

DATED at Calgary, Alberta, on 22 December 1983.

G. J. DeSorcy
Vice Chairman

N. Strom
Board Member

F. J. Mink
Acting Board Member




Boundary Between Reef Rim and Reef Interior

Edge of Reef Build-up

Swan Hills Unit # 1 Boundary

FIGURE 1 Home Oil Company Limited
Application No.830674
Miscible Flood Pattern Area

ERCB

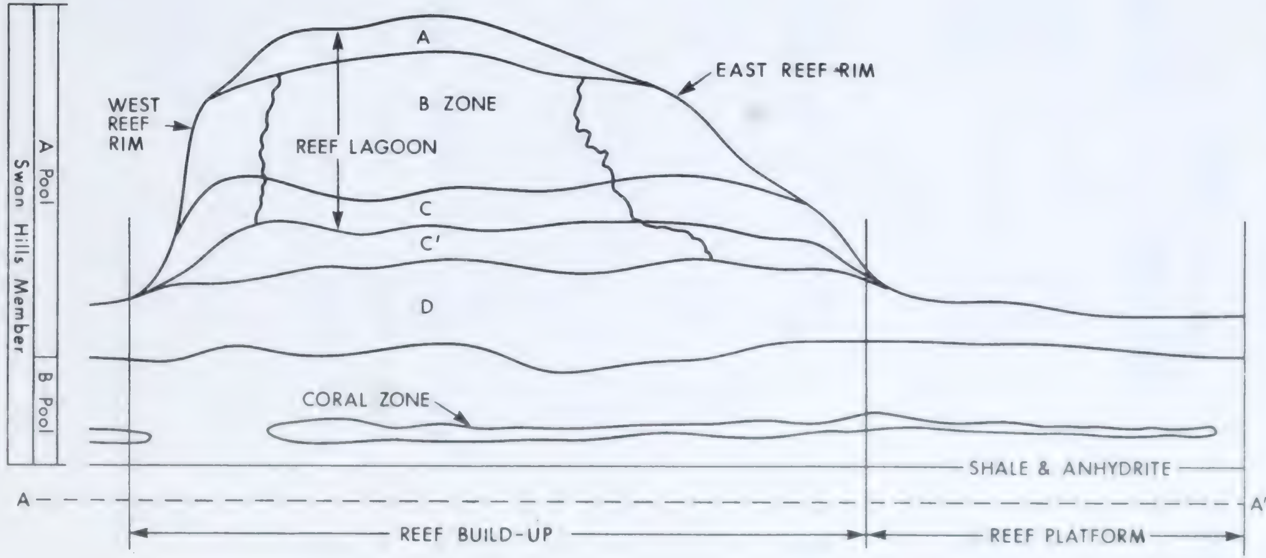



FIGURE 2 Application No. 830674
Schematic Cross Section
West to East
Swan Hills Unit No. 1

TABLE 3 SUMMARY OF MISCIBLE FLOOD RECOVERY

| | HOME | | BOARD |
|---|---|---|---|
| | Reef Rim | Reef Interior | |
| A Waterflood | | | |
| Ri | 0.48 | 0.38 | 0.42 |
| Sorw | 0.27 | 0.30 | 0.30 |
| Ed | 0.671 | 0.634 | 0.634 |
| Es | 0.715 | 0.600 | 0.663 |
| B Miscible | | | |
| Sorm | 0.05 | 0.05 | 0.05 |
| Ed | 0.939 | 0.939 | 0.939 |
| mobility and gravity modifiers | 0.88 | 0.88 | 0.85 |
| improvement in edge losses | 1.00 - 1.05 | 1.00 - 1.05 | 1.025 |
| infill drilling | - | 1.10 | 1.042 |
| Es | 0.629 - 0.661 | 0.581 - 0.610 | 0.602 |
| Ri | 0.591 - 0.621 | 0.546 - 0.573 | 0.565 |
| $\Delta$R | 0.111 - 0.141 | 0.166 - 0.193 | 0.145 |

Ed: displacement efficiency
Es: total sweep efficiency

APPENDIX

FORM OF APPROVAL*

THE PROVINCE OF ALBERTA

OIL AND GAS CONSERVATION ACT

ENERGY RESOURCES CONSERVATION BOARD

IN THE MATTER of a scheme of Home Oil Company Ltd. for enhanced recovery of oil by hydrocarbon solvent and water injection in part of the Swan Hills Beaverhill Lake A & B Pool

APPROVAL NO. ____

The Energy Resources Conservation Board, pursuant to the Oil and Gas Conservation Act, being chapter 0-5 of the Revised Statutes of Alberta, 1980, hereby orders as follows:

1. The scheme of Home Oil Company Ltd. (hereinafter called "the Operator"), as such scheme is described in the letter of application dated 12 July 1983 and supporting submission dated 10 October 1983, from the Operator to the Board, and in testimony given at the hearing of the application on 18 October 1983, for enhanced recovery of oil by hydrocarbon solvent and water injection in that part of the Swan Hills Beaverhill Lake A & B Pool shown outlined on the attachment hereto, marked Appendix A to this approval, is approved, subject to the terms and conditions herein contained.

2. For the purpose of this approval, "solvent" means a suitable mixture of hydrocarbons ranging from methane to pentanes plus, but consisting largely of methane, ethane and propane. The ethane plus content of the solvent shall be of sufficient quantity to obtain first-contact miscibility with the reservoir oil. The ethane plus content will be approximately 83.8 per cent with the exact value to be determined by the procedure described in the subject application using a pressure level of 17 237 kPa(ga).

3. Water, solvent and gas may be injected to the Swan Hills Beaverhill Lake A & B Pool through wells listed on the attachment hereto, marked Appendix B.

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* This is only a form of approval. The approval, when issued, may have minor variations from that set out herein.

4. The injection of solvent and water substantially in accordance with the scheme shall commence on or about 1 July 1985.

5. The solvent or chase gas and water injected through the wells referred to on Appendix B hereto shall be in sufficient volumes to maintain, in the opinion of the Board, a suitable balance between solvent or chase gas and water injected into and fluids withdrawn from each pattern in the project area.

6. Upon commencement of solvent injection, (1) production and injection shall be controlled so that the average reservoir pressure exceeds 18 616 kPa(ga); (2) no production may be taken from any drilling spacing unit in the Swan Hills Beaverhill Lake A & B Pool, wherein the reservoir pressure is less than 17 237 kPa(ga) unless the Board, upon application, permits otherwise.

7. Upon commencement of breakthrough solvent production, total volumes of gas and natural gas liquids produced and sold from Unit No. 1 shall not exceed volumes injected unless the Board, upon application, permits otherwise.

8. (1) The hydrocarbon pore volume for each pattern within the project shall be established by the Operator and agreement thereto confirmed in writing by the Board.

(2) The cumulative volume of solvent to be injected during the life of the scheme shall be not less than 12.9 million cubic metres at reservoir conditions and shall be distributed such that each injection pattern receives a volume of solvent not less than 15 per cent of the hydrocarbon pore volume of the pattern.

9. The cumulative volume of chase gas to be injected during the life of the scheme shall be not less than 28.8 million metres at reservoir conditions and shall be distributed such that each pattern receives a volume of chase gas not less than 30 per cent of the hydrocarbon pore volume of the pattern.

10. Alternate volumes of solvent and water, or chase gas and water, shall be injected in accordance with the scheme, in the wells referred to on Appendix B hereto in such volumes that, at the end of each injection cycle for a given pattern, the ratio of the reservoir volume of water injected to the reservoir volume of solvent or chase gas injected during the cycle shall average 1.0 but may range in any one cycle from 0.72 to 2.25.

11. Upon commencement of solvent injection into the pool, the Operator shall implement a program of sampling and analysis in accordance with the following rules:

(1) The composition of the solvent and chase gas injected into the pool shall be determined and submitted to the Board not less than once each month until such time as the Board permits, in writing, a less frequent interval.

(2) The volume and formation volume factor for chase gas and the reservoir cubic metres of solvent injected shall be submitted to the Board on a monthly basis and shall contain both monthly and cumulative data.

(3) The Operator shall select at least one producing well in each pattern, from which shall be obtained at least one representative sample of the produced liquid and gas every three months. The samples are to be recombined at the producing gas-liquid ratios, and the results used to calculate the composition of the well effluent.

(4) The Operator shall determine the composition of the well effluent prior to solvent and chase gas injection to establish the reference level composition.

(5) When breakthrough of injected hydrocarbon solvent and/or chase gas is indicated in any of the producing wells, the Operator shall obtain and analyse at least one sample of the produced liquid and gas each month from the well at which breakthrough has occurred.

(6) Before a sample is obtained in accordance with rules 3, 4 and 5, the Operator shall produce the well until the volume of gas, oil and water production at reservoir conditions is at least three times the combined volumes of the open casing, tubing and flow line to the point of sampling.

12. (1) The Operator shall monitor the vertical distribution of injected fluids by an injection profile survey to be run at least once, for each fluid injected, in each of the wells referred to on Appendix B hereto.

(2) If an injection well is reworked, an injection profile shall be taken immediately.

13. In addition to the normal reporting requirements specified in section 12.130 of the Oil and Gas Conservation Regulations, the Operator shall report in each progress report submitted for the scheme

(a) in graphical form for each well, the producing gas-oil ratio, water-oil ratio and oil rate in cubic metres per day,

(b) instances of solvent breakthrough and the implications of the breakthrough on the efficacy of the scheme, and

(c) the significance of the information obtained in accordance with clauses 10 and 11.

14. In addition to normal reporting requirements, the Operator shall submit to the Board within two years after commencement of solvent injection, a report evaluating the individual patterns and overall performance of the scheme, including

(a) an evaluation of the underlying assumptions that form the basis for the Operator's volumetric sweep model, estimate of Sorw and hydrocarbon bank size design,

(b) an evaluation of the Operator's injection strategy with particular attention to any problems in controlling the flood,

(c) solvent or chase gas breakthrough performance and the success of any attempts to correct poor injection profiles at injectors or to shut off production of injection fluids at producers, and

(d) feasibility of scheme expansion to a unit-wide hydrocarbon miscible flood.

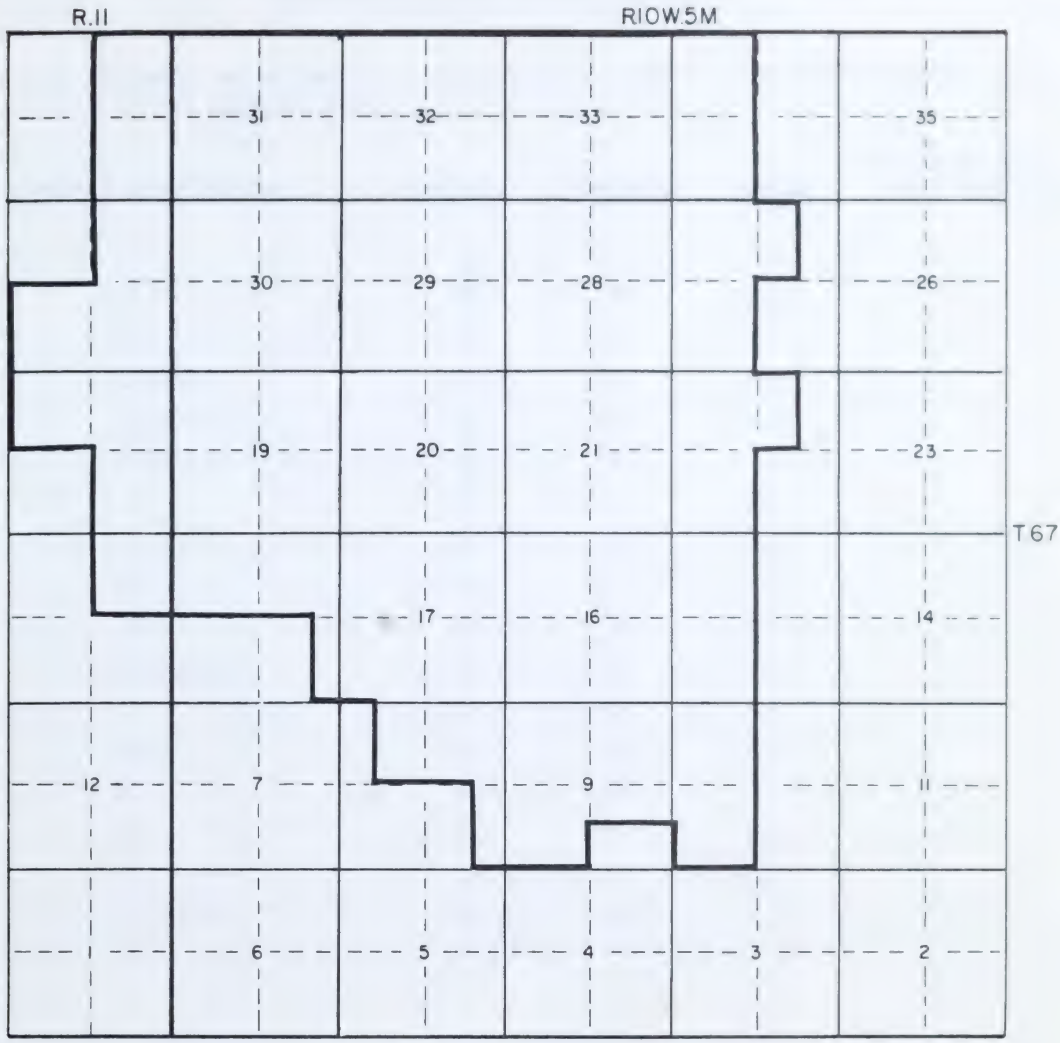
15. In addition to normal reporting requirements, the Operator shall submit prior to commencement of injection

(1) the results of the infill drilling program including an updated geological description, and

(2) the principal sources of gas and natural gas liquids to be injected together with the approximate composition.

MADE at the City of Calgary, in the Province of Alberta, this

ENERGY RESOURCES CONSERVATION BOARD




SWAN HILLS FIELD

ERCB

APPENDIX A TO APPROVAL NO.

AS AMENDED BY APPROVAL NO.

PREVIOUS APPROVAL NO.

AREA OF CHANGE

EFFECTIVE 1983

## APPENDIX B TO APPROVAL NO.

The following is the list of injection wells for the Swan Hills Beaverhill Lake A and B Pool miscible flood:

| Legal Subdivision(s) | Section | Township | Range | (all west of the 5 Meridian) |
|---|---|---|---|---|
| 12 | 9 | 67 | 10 | |
| 12 | 10 | 67 | 10 | |
| 12 | 15 | 67 | 10 | |
| 2 and 12 | 16 | 67 | 10 | |
| 2 and 13 | 17 | 67 | 10 | |
| 4 and 11 | 19 | 67 | 10 | |
| 2 | 20 | 67 | 10 | |
| 2 and 12 | 21 | 67 | 10 | |
| 12 | 22 | 67 | 10 | |
| 12 | 27 | 67 | 10 | |
| 2 and 12 | 28 | 67 | 10 | |
| 2 | 29 | 67 | 10 | |
| 10 | 30 | 67 | 10 | |
| 10 | 31 | 67 | 10 | |
| 2 | 32 | 67 | 10 | |
| 10 | 33 | 67 | 10 | |
| 2 and 10 | 25 | 67 | 11 | |

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATION BY DOME PETROLEUM LIMITED
FOR AN EXPERIMENTAL IN SITU
HEAVY OIL SCHEME IN THE
LINDBERGH AREA

Decision D 83-27
Applications No. 830588 and 830662

## 1 INTRODUCTION

### 1.1 Application 830588

Dome Petroleum Limited (Dome) applied, pursuant to section 26(1) of the Oil and Gas Conservation Act, for approval of an experimental scheme in a portion of the Lindbergh RR & WW Pool in section 24, township 55, range 6, west of the 4th meridian.

Fifty new vertical wells would be drilled and completed, and eleven existing wells would be utilized (see Figure 1). The scheme is designed to recover approximately 210 cubic metres per day of oil. The project life is estimated to be 16 years but the requested term of approval as an experimental scheme was 5 years. The proposed two-phase development would consist of twelve 12.1-hectare (ha) inverted seven-spot patterns and eleven non-pattern wells. Phase I would consist of primary production followed by liquefied petroleum gas (LPG) or carbon dioxide ($CO_2$) injection. Phase II would consist of a combination thermal drive (CTD).

### 1.2 Application 830662

Dome also applied, pursuant to section 4.035 of the Oil and Gas Conservation Regulations, for the suspension of well spacing regulations for the area of the proposed experimental scheme. The spacing in the area is currently one legal subdivision with the target area in the southeast quarter of the legal subdivision.

### 1.3 The Hearing

The applications were originally scheduled to be considered at a public hearing before the Energy Resources Conservation Board (Board) on 12 October 1983 in Elk Point, Alberta. However, no submissions, except one by Gulf Canada Resources, Inc., were filed and the Board rescheduled and changed the location of the hearing to 13 October 1983 in Calgary, Alberta. The division of the Board hearing the application was V. Bohme, P. Eng., C. Goodman, P. Eng., and L. Bellows, P. Eng.

THOSE WHO APPEARED AT THE HEARING

| Principals and Representatives (Abbreviations used in Report) | Witnesses |
|---|---|
| Dome Petroleum Limited (Dome)<br>C. K. Yates | R. M. Scarborough, P. Eng.<br>Dr. P. D. White<br>H. J. Strain, P.Eng.<br>B. R. Croft, P.Eng.<br>D. Lundquist |
| Gulf Canada Resources Inc. (Gulf)<br>A. K. Singhal, P.Eng. | A. K. Singhal, P.Eng. |
| Energy Resources Conservation Board staff (Board staff)<br>K. F. Miller<br>H. O. Lillo, P. Eng.<br>J. R. Nichol, P.Eng.<br>T. W. Dowley, P.Eng.<br>L. D. Martinuzzi, P.Eng. | |

## 2 PRELIMINARY MATTERS

Dome initially applied under section 4.035, subsection 1(a) of the Oil and Gas Conservation Regulations for an order prescribing special drilling spacing units and target areas in accordance with Figure 2. It amended the application to apply under section 4.035, subsection 1(b) since suspension of spacing regulations would allow drilling in the exact locations specified in the application.

## 3 ISSUES

The Board considers that the issues in these applications are:

- experimental nature of the proposed scheme
- environmental considerations
- spacing

## 4 EXPERIMENTAL NATURE OF THE PROPOSED SCHEME

Phase I of the proposed scheme would include a one-year period of primary production and one or more cycles of sequential LPG or $CO_2$ injection and production of the proposed injection wells. The purposes of this phase would be to create voidage around the wellbore, increase gas saturation in the reservoir, and create interwell communication. Each would contribute to improved reservoir injectivity. Dome stated that Phase I would be necessary to allow the proper conditioning of the reservoir for CTD.

Once the reservoir was properly conditioned, Phase II would be initiated. During this phase, six patterns would be ignited using air and steam as the combustion medium. Six months later the remaining six patterns would be ignited. The purpose of this phase would be to allow the injectivity of air and water for a continuous period of time to determine if the CTD process is viable for the future development of the Lindbergh area.

The eleven non-pattern wells are included for the purposes of recovering unswept oil, monitoring of the scheme's progress by analysis of the vent gases, and allowing for blowdown of combustion gases. The non-pattern wells would be located so that they could be used as injectors in any expansion of the scheme.

Gulf supported Dome's view that both phases of the proposed scheme are experimental in nature and expressed full support for the proposal.

The Board is satisfied that Dome has justified the experimental nature of the scheme, specifically Phase I, Phase II, and the non-pattern wells. Successful operation of the scheme would increase the recoverable reserves from this area and improve the knowledge of the CTD process.

## 5 ENVIRONMENTAL CONSIDERATIONS

### 5.1 Diking

The applicant indicated that the landowners in the area do not wish to have tanks or well sites diked, because additional land is lost to cultivation, weeds are a major problem around the diked area, and additional topsoil is disturbed. Dome said that due to the nature of the fluid in the tank, any type of spill would affect only a small area around the site. Dome also stated that tanks would be on site for only two years, at which time treating facilities would be built on section 24. All fluids would then be transported to the central facility by buried pipelines and dikes would be eliminated.

The Board believes that diking would be required on a number of sites on section 24 as required in section 8.030, subsection (1) of the Oil and Gas Conservation Regulations. However, it would authorize its Wainwright Area office to suspend the requirements of subsection (1) in cases where dikes were not necessary.

## 5.2 Vertical Wells versus Directional Wells

Dome submitted a detailed comparison of the drilling and operation of vertical and directional wells. The comparison considered technical, environmental, and economic factors.

Dome stated that even though it would be technically feasible to drill the additional 50 wells directionally from pads, operational problems would offset any advantages. Based on experience with directional wells, Dome said that operating is considerably more difficult and somewhat more expensive than with vertical wells. The major economic difference is the increased cost and frequency of servicing directionally drilled wells.

Dome emphasized that the surface development applied for incorporates several straight east-west lines of wells so as not to unduly impair normal cultivation on the remaining land. Each well site would initially require 1.05 ha of land, but after the well was tied-in to the battery facilities the lease would be reduced to 0.3 ha. When compared to the total land requirement for directional wells from pads, vertical well development would require 29 ha of land, while directional well development would require 21 ha of land. Therefore, only 4 per cent more of the land currently under cultivation is required for vertical wells.

The Board accepts Dome's evidence regarding the additional operating problems and costs of directional wells, and notes that the surface landowners on and adjoining section 24 have no objections to the proposed scheme. For this particular application, the Board agrees that vertical wells are suitable for the development of section 24.

## 5.3 Vent Gas

With respect to vent gas handling, Dome stated that emissions from the scheme would fall within the guidelines set out in the Clean Air Act. The applicant stated that, if odorous gases were detected, portable incinerators would be installed.

The Board notes that Dome must conform to the province's ambient air quality standards and believes that these can be met by the use of well-site incinerators.

# 6 SPACING

As indicated in section 2 of this report, Dome applied under section 4.035, subsection 1(b) for suspension of drilling spacing unit, size, shape, and target area so that wells may be drilled in accordance with an experimental approval. Dome stated that a buffer zone of 100 metres and an interwell distance of 200 metres would be acceptable for section 24. However, Dome also recognized that two existing wells, well 2A and well 8A are within the 100-metre buffer zone, and therefore requested that these two wells be

exempted. The 100-metre buffer zone was requested in order to avoid possible drainage from offset leaseholds. Dome has indicated that there are two existing wells and eight proposed wells within 100 metres of the lease boundary.

Dome submitted letters of support for the project from all adjacent offset mineral leaseholds.

The Board believes that it is appropriate to suspend normal spacing for the project area. Since Dome has shown in its application the location proposed for every well in the project, and these locations conform generally with the concept of the 200-metre interwell distance and a 100-metre buffer zone, the Board agrees with the spacing proposed. The Board's spacing order would therefore require general compliance with the proposed well locations subject to minor adjustments for operational reasons.

## 7 DECISION

Having regard for the evidence and its responsibilities under the Oil and Gas Conservation Act and Regulations, the Board granted Applications 830588 and 830662 at the conclusion of the hearing. The necessary orders and approvals respecting the applications will be issued concurrently with this report.

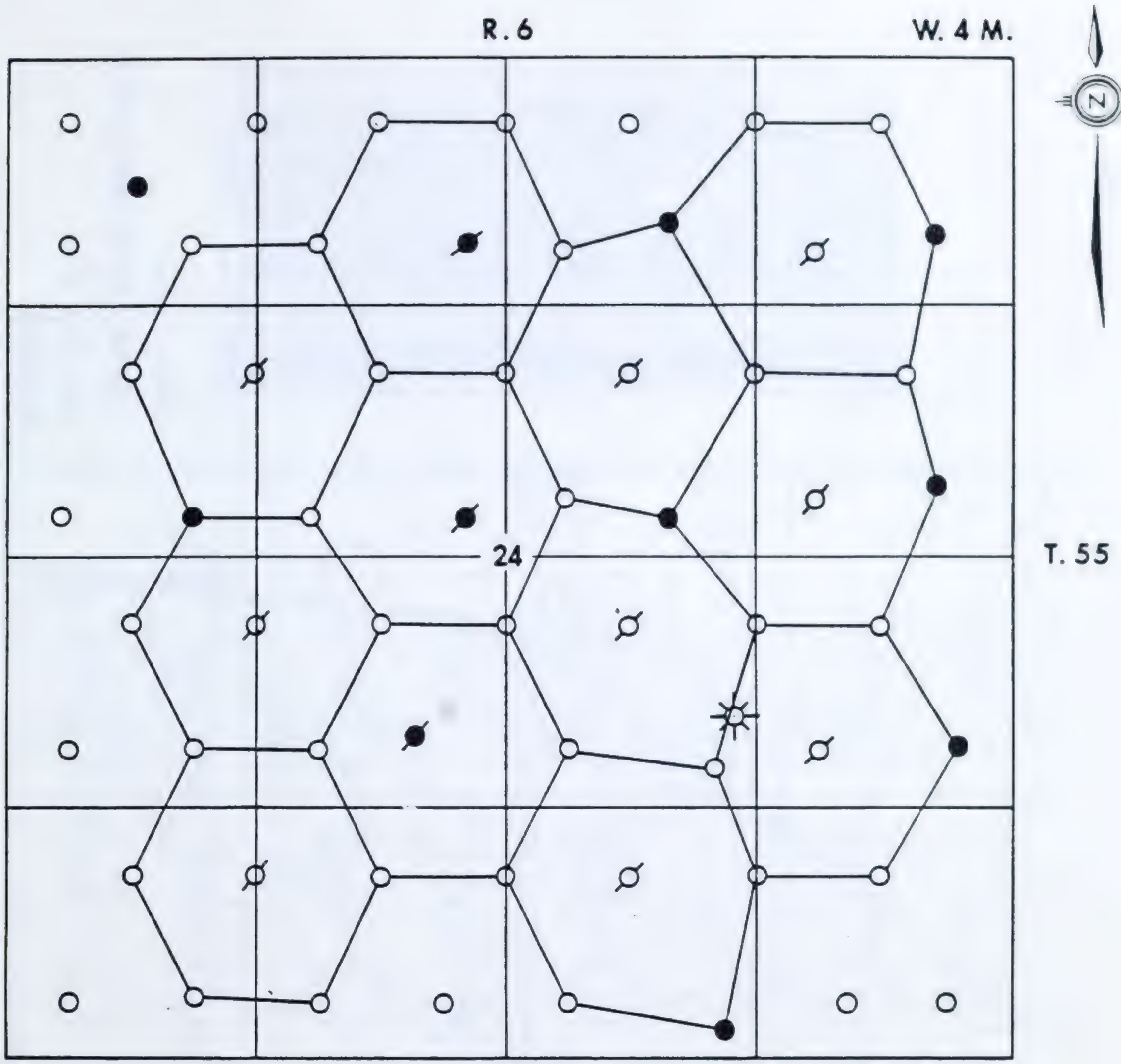
DATED at Calgary, Alberta, on 27 October 1983.

ENERGY RESOURCES CONSERVATION BOARD

V. E. Bohme
V. E. Bohme, P. Eng.
Board Member

C. J. Goodman
C. J. Goodman, P. Eng.
Board Member

L. A. Bellows
L. A. Bellows, P. Eng.
Acting Board Member




LEGEND

- ● EXISTING CUMMINGS ZONE WELL
- ○ PROPOSED PRODUCER
- ⌀ PROPOSED INJECTOR
- CONVERT EXISTING WELL TO INJECTOR
- INTERWELL DISTANCE (166 - 286m)
- MIN. DISTANCE FROM SECTION BOUNDARY ~50m

FIGURE 1

| | |
|---|---|
| AREA | LINDBERGH |
| TITLE | PATTERN DEVELOPMENT<br>Sec. 24-55-6W4M |

**ERCB**

COMPOSITE PLAN

## SEC. 24 · TWP. 55 · RGE. 6 · W.4 M.

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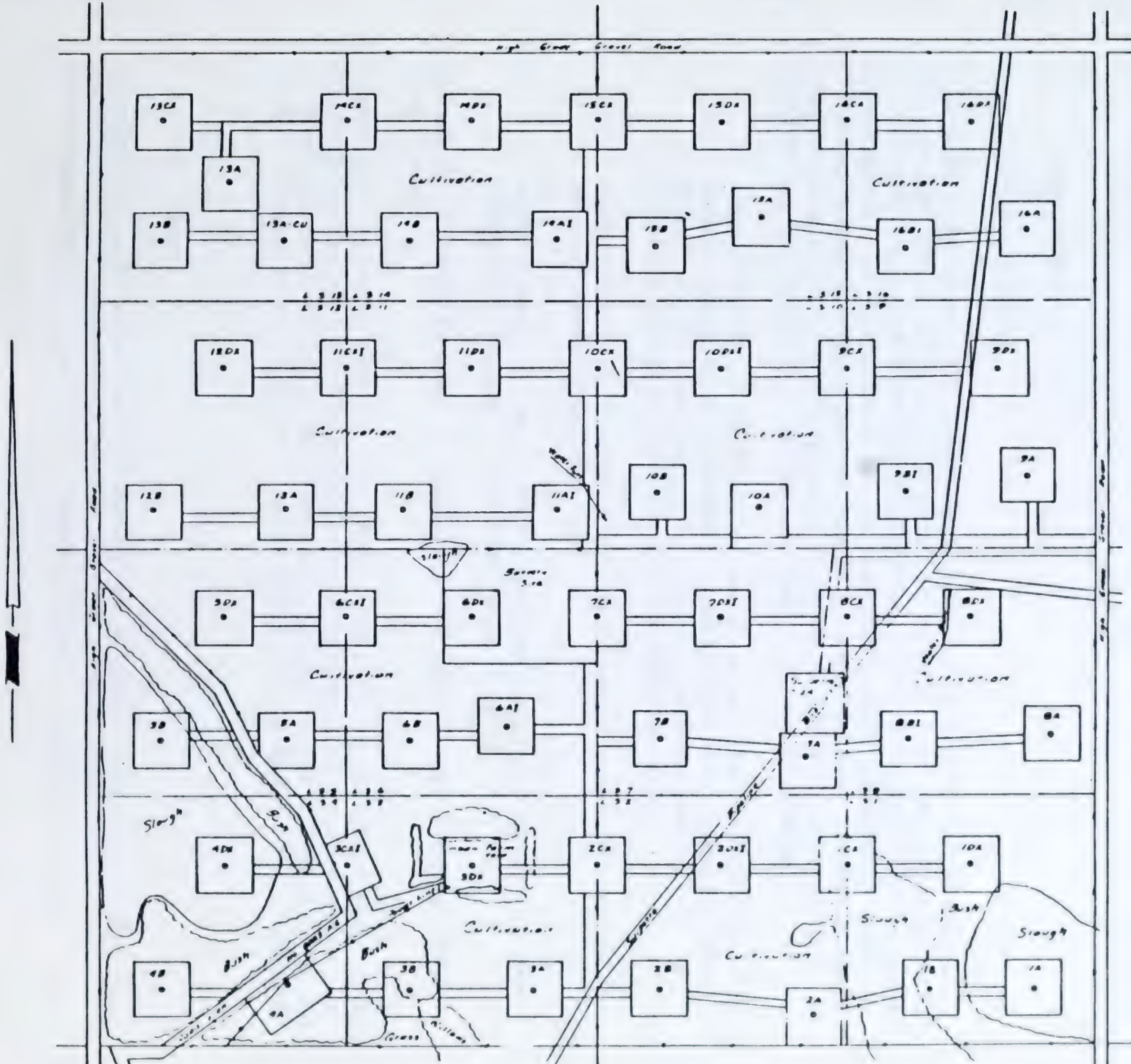


| LOCATION | CO-ORDINATES | |
|---|---|---|
| 1A-24 | 92.00 N of S | 100.69 W of E |
| 1B-24 | 92.00 N of S | 276.77 W of E |
| 1CA-24 | 293.32 N of S | 402.77 W of E |
| 1DA-24 | 293.32 N of S | 201.39 W of E |
| 2A-24 | 30.00 N of S | 432.84 W of E |
| 2B-24 | 92.00 N of S | 704.93 W of E |
| 2CA-24 | 293.32 N of S | 805.54 W of E |
| 2DAI-24 | 293.32 N of S | 604.16 W of E |
| 3A-24 | 92.00 N of S | 704.93 E of W |
| 3B-24 | 92.00 N of S | 503.46 E of W |
| 3CAI-24 | 293.32 N of S | 402.77 E of W |
| 3DA-24 | 293.34 N of S | 604.16 E of W |
| 4A-24 | 92.00 N of S | 302.08 E of W |
| 4B-24 | 92.00 N of S | 100.69 E of W |
| 4DA-24 | 293.32 N of S | 201.39 E of W |
| 5A-24 | 494.62 N of S | 302.08 E of W |
| 5B-24 | 494.62 N of S | 100.69 E of W |
| 5DA-24 | 695.93 N of S | 201.39 E of W |
| 6AI-24 | 517.21 N of S | 669.30 E of W |
| 6B-24 | 494.62 N of S | 503.47 E of W |
| 6CAI-24 | 695.93 N of S | 402.77 E of W |
| 6DA-24 | 695.93 N of S | 604.16 E of W |
| 7A-24 | 461.72 N of S | 461.82 W of E |
| 7B-24 | 494.62 N of S | 704.94 W of E |
| 7CA-24 | 695.93 N of S | 805.54 W of E |
| 7DA-24 | 695.93 N of S | 604.16 W of E |
| 8A-24 | 502.50 N of S | 70.38 W of E |
| 8BI-24 | 494.62 N of S | 302.08 W of E |
| 8CA-24 | 695.93 N of S | 402.77 W of E |
| 8DA-24 | 695.93 N of S | 201.39 W of E |
| 9A-24 | 683.62 S of N | 103.00 W of E |
| 9BI-24 | 713.29 S of N | 302.08 W of E |
| 9CA-24 | 511.93 S of N | 402.77 W of E |
| 9DA-24 | 511.93 S of N | 136.38 W of E |
| 10A-24 | 738.00 S of N | 331.92 W of E |
| 10B-24 | 713.29 S of N | 704.93 W of E |
| 10CA-24 | 511.93 S of N | 805.54 W of E |
| 10DAI-24 | 511.93 S of N | 604.16 W of E |
| 11AI-24 | 733.67 S of N | 790.98 E of W |
| 11B-24 | 733.61 S of N | 493.41 E of W |
| 11CAI-24 | 511.93 S of N | 402.78 E of W |
| 11DA-24 | 511.93 S of N | 604.16 E of W |
| 12A-24 | 739.61 S of N | 301.73 E of W |
| 12B-24 | 739.61 S of N | 90.61 E of W |
| 12DA-24 | 511.93 S of N | 201.39 E of W |
| 13A-24 | 210.00 S of N | 210.00 E of W |
| 13A-CU-24 | 301.73 S of N | 302.03 E of W |
| 13B-24 | 301.73 S of N | 100.67 E of W |
| 13CA-24 | 109.31 S of N | 100.69 E of W |
| 14AI-24 | 301.73 S of N | 790.98 E of W |
| 14B-24 | 301.73 S of N | 503.44 E of W |
| 14CA-24 | 109.31 S of N | 402.77 E of W |
| 14DA-24 | 109.31 S of N | 604.16 E of W |
| 15A-24 | 262.72 S of N | 831.98 W of E |
| 15B-24 | 310.62 S of N | 704.93 W of E |
| 15CA-24 | 109.31 S of N | 805.54 W of E |
| 15DA-24 | 109.31 S of N | 604.16 W of E |
| 16A-24 | 282.32 S of N | 103.00 W of E |
| 16BI-24 | 310.92 S of N | 302.08 W of E |
| 16CA-24 | 109.31 S of N | 402.77 W of E |
| 16DA-24 | 109.31 S of N | 201.39 W of E |

FIGURE 2

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta



APPLICATION BY FEDERATED PIPE LINES LTD. FOR APPROVAL TO AMEND PIPELINE LICENCES TO ALLOW THE TRANSPORT OF HIGH VAPOUR PRESSURE PRODUCTS AND FOR A PERMIT TO CONSTRUCT HIGH VAPOUR PRESSURE PIPELINES IN THE FORT SASKATCHEWAN, MORINVILLE, AND SWAN HILLS AREAS

Decision D 83-28
Application 830394

# 1 INTRODUCTION

## 1.1 The Application

Federated Pipe Lines Ltd. (Federated) applied to the Energy Resources Conservation Board (the Board), pursuant to Part 4 of the Pipeline Act, for approval to amend Pipeline Licences No. 114, 904, and 4956 to convert approximately 217 kilometres (km) of existing 323.9-millimetre (mm), 273.1-mm, and 168.3-mm, diameter pipeline from Edmonton to Swan Hills from crude oil service to high vapour pressure (HVP) service. The application was also for a permit to construct the following:

- o approximately 24 km of 273.1-mm diameter pipeline from the Fort Saskatchewan area to connect with the existing pipeline near Namao, or alternatively, to construct approximately 1 km of 219.1-mm diameter pipeline in the Edmonton area,
- o approximately 3.1 km of 273.1-mm diameter pipeline through the Town of Morinville, and
- o approximately 13 km of 219.1-mm diameter and 8 km of 168.3-mm diameter pipeline in the Swan Hills area,

all of which would be used to transport HVP natural gas liquids (NGLs) (see Figure 1).

Immediately prior to the hearing, Federated advised the Board that it was withdrawing the part of its application that proposed as an alternative to construct 1 km of 219.1-mm diameter pipeline in the Edmonton area and convert a section of pipeline between Edmonton and Namao from crude oil service to HVP service.

## 1.2 The Hearing

Federated's application was considered at a public hearing on 3 and 4 October 1983 at Edmonton, Alberta, with G. J. DeSorcy, P.Eng, V. E. Bohme, P.Eng., and C. J. Goodman, P.Eng., sitting.

Participants at the hearing are identified in the following table.

THOSE WHO APPEARED AT THE HEARING

| Principals and Representatives (Abbreviations used in Report) | Witnesses |
|---|---|
| Federated Pipe Lines Ltd. (Federated)<br>R. M. Perrin | R. C. Osborne<br>W. Sidjak, P.Eng. (of Sidjak and Associates Ltd.)<br>W. A. Jackson, P.Eng.<br>B. Singleton, P.Eng. (of Singleton Associated Engineering Ltd.)<br>G. R. Evans<br>S. J. Stefanowski<br>A. M. McLean, P.Eng. (of A. Murray McLean & Assoicates Ltd.)<br>Dr. F. G. Bercha, P.Eng. (of F. G. Bercha and Associates Limited)<br>J. R. Wurzer |
| Amoco Canada Petroleum Company Ltd.<br>R. Brannigan | |
| Dome Petroleum Limited<br>W. Smith | |
| Esso Resources Canada Limited (Esso)<br>P. L. Miller | |
| Noranda Gas Industries<br>E. B. McCallion | |
| Town of Morinville (Town)<br>R. Quinn, Mayor<br>G. Maxwell, P.Eng. | R. Quinn, Mayor<br>G. Maxwell, P.Eng. (of Merge Consulting Ltd.) |
| Qualico Developments Ltd. (Qualico)<br>D. VanVeldhuisen, P.Eng. | D. VanVeldhuisen, P.Eng. |
| Guaranty Properties Limited (Guaranty Properties)<br>G. D. Woo, P.Eng. | G. D. Woo, P.Eng. |
| N. Nikiforuk (Mr. Nikiforuk) | N. Nikiforuk |

THOSE WHO APPEARED AT THE HEARING (continued)

| Principals and Representatives (Abbreviations used in Report) | Witnesses |
|---|---|
| Alberta Hospital Edmonton (AHE)<br>T. Collier | |
| City of Edmonton<br>M. McEvoy | |
| Alberta Environment<br>T. Bossenberry | |
| Energy Resources Conservation Board staff<br>M. J. Bruni<br>G. C. Dunn, P.Eng.<br>B. C. Hubbard, P.Eng. | |

At the outset of the hearing, when it became clear that the applicant had withdrawn the portion of its application which proposed, as an alternative, the conversion of existing line and the construction of new line in the Edmonton-Namao area, the City of Edmonton and Alberta Hospital Edmonton withdrew from the proceeding as they were no longer potentially impacted.

## 2 ISSUES

The Board believes the issues pertinent to Federated's application are:

- o the purpose and necessity of the proposed project,
- o the technical design and adequacy of the existing pipeline for the intended HVP service,
- o the routing of the proposed new sections of pipeline, and
- o the appropriateness of locating an HVP pipeline within the Town of Morinville.

## 3 PURPOSE AND NECESSITY

### 3.1 Views of Federated

Federated stated that the purpose of the project is to transport natural gas liquids (NGLs) from the Edmonton area to the Swan Hills and Judy Creek areas for use in proposed miscible-flood schemes for enhanced oil recovery. Federated submitted evidence that Esso's proposed enhanced-recovery project in the Judy Creek area would require approximately 17 600 barrels per day (bpd) (2800 cubic metres per day ($m^3/d$)) and

Home Oil Limited's (Home) proposed flood scheme in the Swan Hills area would require approximately 26 000 bpd (4130 $m^3$/d). Federated stated that these volumes of NGLs are not available in the region of the proposed schemes and that the most logical sources for the required NGLs would be from the Deep Basin area or from the Fort Saskatchewan area. Although the proposed facilities would tie into ethane sources at Fort Saskatchewan, Federated also indicated that it may be feasible to interconnect its proposed pipeline with a Peace PipeLine Ltd. (Peace Pipe) line that presently transports Deep Basin NGLs to Fort Saskatchewan. The two pipelines cross near Namao and an interconnection at this point would make it possible for Federated to ship Deep Basin NGLs to Swan Hills and Judy Creek.

Federated stated that the producers (Home and Esso) expected to recover an incremental 120 million barrels (19 000 $10^3$ $m^3$) of oil by operating enhanced-recovery schemes in the Swan Hills Unit 1 and Judy Creek A pools.

Federated also stated that the cost of the proposed conversion of its existing pipeline to HVP service and the construction of the proposed new sections of pipeline would cost approximately $11.5 million. Federated expected the minimum life of the proposed project would be 10 years and that the actual life would be dependent on the sequencing of miscible-flood schemes in the delivery area and on the future availability of NGLs within the area.

## 3.2 Views of the Board

The Board believes that the expected incremental oil recovery of 19 000 $10^3$ $m^3$ from the Swan Hills Unit 1 and Judy Creek A pools would be beneficial to the operators and the province and that the enchanced-recovery schemes should proceed if feasible, and subject to satisfying regulatory requirements.

The Board agrees with Federated that an adequate source of NGLs to supply the miscible-flood schemes does not exist in the Swan Hills-Judy Creek area at this time and that, if the enhanced-recovery programs are to proceed as planned, there is a need to deliver NGLs into the area from some outside source. The Board believes that in general, the Federated project is a reasonable proposal, subject to some specific considerations that will be discussed later.

For this reason, and bearing in mind that no interveners at the hearing questioned the purpose of Federated's application, the Board is satisfied that a purpose and necessity for the proposed pipeline system has been demonstrated.

# 4 GENERAL TECHNICAL DESIGN AND ADEQUACY OF EXISTING PIPE

## 4.1 Views of Federated

Federated's application indicated that its plan to transport miscible flood agent to the Swan Hills area involves the construction of approximately 48 km of new pipeline as well as upgrading and retesting approximately 217 km of existing oil pipeline.

The company indicated that all new construction would meet the requirements of CSA Z183-M1982 "Oil Pipeline Transportation Systems" for high vapour pressure service. In fact, Federated proposed to construct the Fort Saskatchewan-Namao section to Zone 2 location[1] standards (currently this section of pipeline is not a Zone 2 location). Proposed construction through the Town of Morinville would also exceed the CSA standard requirement for depth of cover and pipeline protection.

Federated requested pipeline licence amendments for three existing pipeline licences (licences no. 114, 904, and 4956). Amendments would provide for increased maximum operating pressure, reversed direction of flow, and a change of substance to be transported.

In support of the application, Federated filed results of hydrostatic tests as well as certain other destructive tests. Federated also indicated that the pipeline would be inspected with an internal inspection pig and hydrostatically pressure tested throughout its length prior to its conversion to HVP service. The company indicated that the internal inspection pig would detect any damage to the pipe by external forces as well as pipe or corrosion defects. On the matter of hydrostatic pressure testing, Federated stated that the pressure tests would verify the integrity of the pipeline. Although two of three representative hydrostatic test sections of the pipeline had experienced failures, Federated stated that the results were predictable in that the initial failures occurred quickly and at a lower stress, and subsequent failures occurred after a somewhat longer period of time and at a higher stress level. On each of the two failed sections, the third attempt resulted in successful hydrostatic tests.

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1 As defined in CSA Z183-M1982 standard for Oil Pipeline Transportation Systems, " A Zone 2 location is an area extending 200 metres on either side of the centerline of any continuous 1 km length of pipeline that contains more than 5 dwelling units intended for human occupancy, or is a facility that contains 20 or more persons during normal use."

The company removed samples of the pipe material adjacent to each of the failure locations and examined the material by laboratory testing. Laboratory testing included pipe body tensile, weld tensile, and flattening tests, microspecimen examination, and chemical analysis. One of thirteen pipe body tensile samples failed to meet the elongation criteria of 27 per cent. The elongation reported was 25 per cent. In addition, four samples failed the 3 o'clock flattening tests. The company's metallurgical consultant, Mr. McLean, indicated that the associated microspecimens showed a higher-than-normal welding heat pattern to the outside pipe surface on two samples and a lower-than-normal welding heat pattern to the outside surface on the other two samples. There was also evidence of a hook crack in one of the samples. These defects were given as the reasons for the failure of the pipe to meet the flattening tests.

Mr. McLean, expressed the opinion that the laboratory testing indicated the existing pipeline was suitable for the service intended and meets the specification requirements of API 5LX42-1957 and, with very few exceptions, the requirements of the current CSA Z245.1-M1982 Grade 290 Category 1.

The company also conducted reverse guided bend, nick break, and tensile tests on four field weld samples. All tests proved satisfactory and fracture occurred off weld. Mr. McLean also commented on the surface condition of the pipe indicating that the internal surface was visually inspected and found to be in excellent condition. It was also pointed out that the external condition was found to be in excellent condition with the coating remaining in good condition.

### 4.2 Views of the Interveners

None of the interveners questioned the company or presented any other evidence with regard to the suitability of the existing pipeline.

### 4.3 Views of the Board

The Board has carefully reviewed the details of the application together with the preliminary hydrostatic pressure test results and laboratory tests. It generally agrees with the philosophy of the company with regard to the location of potential defects through the hydrostatic pressure testing procedure proposed. It believes that the hydrostatic test failure pattern found by Federated would likely be typical of the entire pipeline and the pressure testing procedure would locate spots of decreasing defect size as the pressure and duration were increased.

Although the Board believes that the pressure testing procedure is appropriate, it is not prepared to accept these results by themselves as a final determination of acceptability of the pipeline. The Board notes the results of the destructive tests performed on pipe samples taken

adjacent to the hydrostatic pressure test failure locations and believes that this demonstrates inherent weaknesses in the pipe material. In the Board's judgement, such weaknesses would be precluded by standards set out in CSA Z245.1 M-1982, Steel Line Pipe, the state-of-the-art today. The Board agrees that from the viewpoint of chemical analysis and pipe body material, the pipe is substantially equivalent to today's material requirements. The hydrostatic pressure tests and destructive tests affecting the mill weld indicate to the Board that the mill weld joint integrity may not have the reliability necessary to assign the same strength to it as to the pipe body material. It is specifically in this area that the pipe integrity must be proven.

The Board also notes the comments of Mr. McLean to the effect that "the safe testing level for an older pipeline should be someplace around the pressure where you get initial failures." Although the Board does not necessarily agree with Mr. McLean on this point, the comment suggests to the Board that the pipe does not have the same capabilities as new pipe and therefore some allowance should be made for this. The Board believes that the maximum operating pressure (MOP) for old pipe should be restricted to a level where the factor of safety is equal to that for new pipe under the same conditions. Specifically, the Board believes that the margin of safety between the MOP and the minimum hydrostatic test pressure must be increased to achieve the same factor of safety. The Board has reviewed published, documented test results from hydrostatic testing of other pipelines and believes that the margin of safety between MOP and minimum test pressure should be maintained at 30 per cent. (ie ratio of MOP to minimum test pressure shall not exceed 0.7). Therefore, if Federated test the pipeline to a level of 80 per cent of specified minimum yield strength (SMYS), the maximum operating pressure shall be restricted to 56 per cent SMYS. Pressure testing to a minimum of 90 per cent SMYS would therefore increase the MOP to 63 per cent SMYS.

In order to prove the reliability, and consistent with the evidence given, the Board believes further testing and evaluation is necessary and will require the company to perform the following tests and evaluations:

1. The company shall hydrostatically pressure test the pipeline to a level necessary to achieve a 30 per cent margin between MOP and minimum hydrostatic pressure.

2. At each break or leak location the company shall remove the full length of pipe containing the failure. From each failed section of pipe the company shall perform the following tests and inspections:

   (a) two flattening tests, 12 o'clock position
   (b) two flattening tests, 3 o'clock position
   (c) one microspecimen mill weld
   (d) one microspecimen rupture edge
   (e) one chemical analysis

3. In addition, sufficient length of both pipes immediately adjacent to a failed joint (length of pipe) shall be removed with the failed joint and the following tests and inspections performed:

   (a) two tensile tests (each joint) - mill weld
   (b) two guided bend tests (each joint) - mill weld
   (c) two nick fractures (each joint) - mill weld
   (d) one 12 o'clock flattening test (each joint)
   (e) one 3 o'clock flattening test (each joint)
   (f) one microspecimen - mill weld
   (g) one chemical analysis (each joint)

The Board also suggests that tensile, guided bend, and nick fracture tests be conducted, on a sampling basis, on field welds made available by the destructive testing program to demonstrate the integrity of the field welding.

Prior to pressure testing, the company shall submit a detailed plan of the proposed hydrostatic testing program with proposed acceptance criteria for review by the Board. The company shall retain an independent third-party materials and testing consultant to perform and/or supervise all destructive testing and materials evaluations.

A detailed final report of testing shall be submitted to the Board upon completion of the program. The detailed evaluation of test results may contain recommendations as to the suitability of the pipeline for the service intended; however, the Board intends to evaluate the pipeline on the basis of acceptability compared to the present CSA Z183-M1982 standard. Defects appearing in failed pipe joints will be analysed but all defects of significance will be considered to be located and removed by the procedure. Defects located in adjoining pipes will be assessed on the type and frequency of defect. In general terms, the Board would consider any 12 o'clock flattening test failures from non-failing joints of pipe to be reason for rejection. The Board would only be prepared to accept a statistically insignificant number of 3 o'clock flattening test failures from the pipe joints adjacent to the failure locations. All test results will be reviewed by the Board prior to granting approval to amend the licences.

The Board has reviewed the design of the sections of new pipeline and finds the proposal acceptable in this respect.

## 5 SUITABILITY OF THE PROPOSED ROUTE

### 5.1 Views of Federated

Federated said its proposed route between Fort Saskatchewan and Namao crosses agricultural land and includes routing adjustments made to eliminate or minimize impact on agriculture, the environment, and archeological resources.

The proposed routing between Fort Saskatchewan and Namao would make use of an existing spare 273.1-mm diameter pipe crossing under the North Saskatchewan River. Use of this spare pipe would significantly reduce environmental impact of the river crossing.

In response to a request from Mr. Nikiforuk, the owner of the northeast quarter of section 14, township 55, range 23, west of the 4th meridian, Federated agreed to reroute a short section of the pipeline to avoid constructing through a ridge of sand which runs diagonally across Mr. Nikiforuk's land.

## 5.2 Views of the Interveners

Mr. Nikiforuk objected to part of Federated's proposed route between Fort Saskatchewan and Namao because the pipeline would be constructed through a ridge of sand that runs diagonally across his quarter section. Mr. Nikiforuk stated that he is presently using sand from the deposit for his own use and has plans to develop it commercially.

Aside from Mr. Nikiforuk's request, the only other location where there was objection to the proposed routing was in the Town of Morinville. The Town of Morinville, Qualico, and Guaranty Properties objected to Federated's proposal to construct a section of new pipe in its existing right of way within the town. The interveners suggested that the line should be rerouted around the town boundary.

## 5.3 Views of the Board

The Board is satisfied that Federated has selected the proposed route for the new construction as the best route to minimize environmental impact and land-use conflicts. It also believes that Federated's proposed environmental protection and right of way reclamation procedures should result in no significant permanent damage following pipeline construction.

The Board notes that Federated had notified all landowners and occupants affected by the proposed new construction of its plans and that the only objection to the proposed pipeline route, other than through the Town of Morinville, was by Mr. Nikiforuk. Since Federated agreed to Mr. Nikiforuk's proposed realignment along the north boundary of his quarter section, and there were no other landowner objections, the Board assumes that Federated's applied-for routes for the new construction sections are acceptable to all other affected landowners and occupants.

The Board's consideration of the matter of routing the pipeline through or around the Town of Morinville follows in section 6.

## 6 THE APPROPRIATENESS OF AN HVP PIPELINE WITHIN THE TOWN OF MORINVILLE

### 6.1 Views of Federated

Federated's proposal includes the construction of approximately 3.1 km of new pipeline within its existing right of way through the Town of Morinville. The new section of line, intended to replace the section of the crude oil line located in the town, is necessary because the existing line would not have had sufficient wall thickness to satisfy the maximum operating stress level requirements for a Zone 2 location as specified in the CSA Z183-M1982 Standard for Oil Pipeline Construction.

To reduce the possibility of third-party damage to the section of line within the town, Federated stated that it intended to install the pipeline between two other existing pipelines in the right of way with a depth of cover of 180 centimetres (cm). It also said there would be a 4-inch (10-cm) thick slab of concrete placed 2 feet (60 cm) above the line. Federated expressed a belief that these measures would adequately protect the line from third-party damage from above and from the sides.

To address the matter of the safety aspect of operating the HVP line within the town, Federated commissioned a consultant, Dr. Bercha, to determine the level of risk that would be imposed on the residents by the presence of the HVP line. He analysed the probability of a significant release of NGLs from the pipeline occurring (initiating event), and analysed the consequences that might result if a significant release did occur.

In conducting the initiating event analysis, Dr. Bercha utilized the Board's pipeline failure statistics and determined that the probability of a significant product release from an HVP line is about $4.35 \times 10^{-4}$ occurrences/km/year. He stated that the records indicate that about 50 per cent of significant releases from HVP pipelines are caused by third-party damage and expressed the opinion that the proposed protection measures for the pipeline within the town limits would eliminate 85 per cent of the probability of third-party damage. This results in a 38 per cent reduction in the probability of an initiating event occurring. Dr. Bercha, on behalf of Federated, concluded that the probability of a significant release of NGLs from the pipeline within the town would be $2.63 \times 10^{-4}$ occurrences/km/year.

In conducting his consequence analysis, Dr. Bercha assumed that a failure of the pipeline would cause a section of line (one of three segments separated by automatic valves either entering, within, or leaving the Zone 2 area in Morinville) to empty completely. Different atmospheric conditions, each with its own probability of occurrence in the Morinville area, were assumed to occur, resulting in dispersion of the released NGLs over a period of 5 minutes. This defined a vapour cloud size in terms of the extent of the upper and lower flammability limits after

5 minutes, at which time ignition was assumed to occur. To be conservative, the consequence analysis assumed that the ignition of the vapour cloud resulted in an explosion rather than a fire. Specifically, Dr. Bercha's analysis predicted a vapour cloud size of approximately 1000 feet (305 metres) diameter resulting from a failure of the line.

Based on the existing population distribution within the town relative to the location of the proposed pipeline, Federated's consequence analysis in conjunction with the initiating event analysis predicted that the probability of an individual fatality would be $1.2 \times 10^{-6}$ per year and the probability of an accident affecting more than 100 people would be $1 \times 10^{-6}$ per year. Dr. Bercha stated that these risks are comparable to that associated with commercial aircraft travel and 100 times less than the risk associated with automobile travel.

In response to the suggestion by interveners that the pipeline would be safer if located outside the town, Federated stated that the probablility of an initiating event would probably be greater for the pipeline located outside the town because it would not be protected from third-party damage by the same means as the pipeline located within the town. Federated agreed qualitatively that the consequences of a pipeline failure would be less for the pipeline located outside the town but stated that a separation distance between the pipeline and the town boundary of 1000 feet (305 metres) would be necessary to result in a significant reduction of the consequence probability.

Federated estimated that the cost for a route adjacent to the east and north boundary of the town would be approximately $250 000 more than the cost of its proposed route through the town. Rerouting the proposed line farther away from the town would increase the length and the cost would increase accordingly at a rate of $20 000 per diameter-inch-mile or just over $200 000 per mile.

Federated stated that it expects the minimum time that the proposed pipeline through the town would be required for HVP service to be 10 years. The maximum expected time would be 20 years. The actual operating time in HVP service for the pipeline would be dependent on the success of the initial proposed enhanced-recovery schemes, the staging of future schemes, and the availability of NGLs either in the area of the proposed schemes or from another source. Federated also stated that it might request at some time to utilize the line to ship NGLs from the Swan Hills-Judy Creek area to Edmonton, which could extend the life of the line in HVP service beyond 20 years.

In response to questioning, Federated stated that its initiating event analysis did not consider that the pipeline right of way through the town might be subjected to a higher degree of third-party activity than usual because of the development that is likely to occur adjacent to the right of way over the life of the pipeline.

## 6.2 Views of the Interveners

The Town of Morinville, Qualico, and Guaranty Properties were opposed to Federated's proposal to operate an HVP pipeline within the town. All three parties suggested that the proposed line should be rerouted around the town. The three possible alternative routes that were discussed at the hearing are shown on Figure 2.

Qualico stated that Federated's existing right of way through the town traverses two quarter sections of land owned by Qualico, one of which is already partially developed. Qualico expressed concern for the safety of residents of its existing subdivision and future residents of its proposed subdivision that would be located adjacent to Federated's HVP pipeline. Qualico also believed that the marketability of its subdivisions would be affected by the presence of the HVP pipeline because of the fears of prospective home purchasers.

Qualico recommended that the pipeline be rerouted 1000 feet (305 metres) outside the east and north boundaries of the town. Qualico estimated that this could be done for an additional cost of only 2.1 per cent of the total project cost. Qualico also suggested that, notwithstanding Federated's proposed measures to protect the pipeline from third-party damage, there would be less chance of third-party damage occurring to the line if it was located outside the town rather than in the town in an area likely to be subject to a high degree of third-party activity. Qualico also suggested that if the line was located outside the town, it might allow sufficient time to implement an evacuation plan for the town in the event of a failure.

Guaranty Properties stated that its experience had been that pipelines such as that proposed by Federated or other hazardous goods transportation facilities presented very serious planning problems to developers. The public's perception of the safety hazards associated with these types of facilities has resulted in strong public opinion and consequent reaction by political bodies. Subdivision approving authorities have taken a strong and sometimes unrealistic position with respect to subdivision of land adjacent to pipelines. Guaranty Properties stated that it is concerned that it would not be able to get the necessary approvals for its proposed subdivision in the town if Federated's pipeline is installed as proposed.

Guaranty Properties also expressed concern that it would be unable to market its proposed subdivision near the Federated pipeline, again because of the public's perception of a safety hazard. It stated that, notwithstanding Federated's evidence regarding the low probability of injury or property damage and the proposed third-party damage prevention measures, as a developer, it would not be able to convince prospective home buyers of the safety of the pipeline. Guaranty Properties suggested that the safest and most politically acceptable solution would be to reroute the pipeline around the Town of Morinville and that consideration of the cost of doing so should be secondary to public safety.

The Town of Morinville stated that it had grave concerns about the proposed HVP pipeline being located in residential areas. Its concern for the safety of its residents and the psychological impact on them is the prime reason for the Town requesting that the pipeline be relocated. The Town suggested that the line be located about a mile (1.61 km) from the east and north town boundaries in the interests of long-term planning. This would allow space for growth of the town of one half mile (800 m) in both the east and north directions and still maintain a one half mile (800 m) setback distance from the pipeline.

In response to questioning, the Town stated that the town would not likely grow beyond its present east and north boundaries within the next 20 years. If it was certain that the line would not be operated beyond 10 years the Town would still recommend that the line be rerouted but it could then be located only 1000 feet (305 m) outside the east and north boundaries. The Town also stated that if the pipeline was constructed in the town and would only be operated for 10 years, it might consider restricting development of land adjacent to the right of way until the pipeline was abandoned.

A secondary concern that the Town of Morinville had was that the installation of the pipeline as proposed by Federated might interfere with plans to install four major storm sewer crossings of Federated's right of way. The elevations of the endpoints of the storm sewers are already fixed by topography or existing engineering structures and hence, the elevation of the storm sewer at the pipeline crossing location is fixed. With Federated's proposed additional 2 feet (60 cm) of cover over its pipeline to prevent third-party damage, the Town was unsure whether it would be able to install its storm sewers beneath Federated's pipeline. The Town indicated that in general, the installation cost of all the proposed sewer and water lines that have to cross Federated's pipeline would be higher because of the extra caution required.

## 6.3 Views of the Board

The Board has reviewed the risk analysis evidence presented by Dr. Bercha, on behalf of Federated, and accepts the methodology used. The Board notes his opinion that the parameters used in analysing the risk were such that the final results are conservative. The Board believes however that in conducting the initiating event analysis, it might have been more appropriate to have included some factor that reflected the high degree of third-party construction activity that is likely to occur near the pipeline given its proposed location through the town, particularly if it were to remain in HVP service for some 20 years. Similarly, with respect to the consequence analysis, the Board believes that it would have been more appropriate to have had regard for the future development of the town and to have assumed a population density consistent with a residential development adjacent to the right of way rather than the existing population distribution. The Board recognizes that these two matters might not significantly alter the results of the risk analysis but would point out that the results may not be as conservative as Federated suggests.

With respect to the actual calculated individual risk figure of 1.2 x $10^{-6}$ per year, the Board agrees that this is small and quite likely could be less than the risk associated with other hazardous goods transportation networks or industrial facilities adjacent to residential areas. However, the Board believes that, because of the nature of the consequences as reflected by Dr. Bercha's evidence that the chances of an accident affecting 100 or more persons is also about 1 x $10^{-6}$ per year, it is essential that the risk should be very small. With this objective in mind, the Board believes that any reasonable capital expenditure or engineering measures which would significantly reduce the risk must be carefully considered.

Recognizing the recommendations by the Town of Morinville, Qualico, and Guaranty Properties that the proposed pipeline should be located outside the town, the Board has evaluated the three alternative routes that were discussed at the hearing. These are: a route that would follow the east and north boundaries of the town, a route that would maintain a 305-m (1000-foot) separation distance from the east and north boundaries of the town, and finally a route that would maintain a 1.61-km (one-mile) separation distance from the east and north town boundaries.

With respect to the route that would follow the east and north boundary, the Board does not see that there would be significant benefits in constructing the pipeline on this route compared with the route through the town. Indeed, examination of the air photo mosaic map of the town (submitted by Federated as Exhibit Number 24) shows that there is more existing residential development adjacent to the route along the town boundaries at the present time than along the route through the town. The Board also notes the comment of Federated's risk consultant that, qualitatively, a separation distance of at least 1000 feet (305 m) would be required to significantly reduce the risk. The Board therefore considers this route to be inappropriate since the risk of accidents and likely consequence would not be reduced enough to justify the extra costs

In considering the route proposed by the Town of Morinville that would maintain a separation distance of 1 mile (1.61 km) from the town boundaries, the Board estimates the cost of a pipeline on this route to be approximately \$1.3 million. This is based on installing approximately 10.5 km (6.3 miles) at a cost of \$200 000 per mile as estimated by Federated. The Board estimates the cost of constructing the 3.1 km of pipeline through the town to be approximately \$450 000 based on the \$200 000 per mile cost plus an additional cost of 15 per cent for Federated's proposed third-party damage mitigation measures. (The Board notes that Federated suggested that the special mitigative measures would be required even if the line by-passed the town but the Board does not believe this would be necessary, with the possible exception of a route immediately adjacent to the town boundary.) Therefore, the Board estimates the incremental cost of the one-mile separation distance route to be some \$850 000 or 7.4 per cent of the total project cost.

In terms of risk to Morinville residents from a pipeline located 1.61 km from the town, the Board would expect it to be almost nil. The Board notes that this route was suggested by the Town of Morinville with proposed expansion beyond the present east and north town boundaries in mind. The Town also stated that if the operating life of the proposed pipeline would be about 10 years, it would find a route located 1000 feet (305 m) from the town boundaries to be acceptable because the town would not likely grow beyond the existing boundaries within the next 20 years.

The third route that was discussed at the hearing would locate the pipeline 305 m (1000 feet) outside the east and north boundaries. This route was suggested by Qualico and Guaranty Properties. The Board made a similar cost estimate for this route as in the first case and found the incremental cost would be some $240 000 or approximately 2.1 per cent of the total project cost. The Board would expect the risk of serious accident in terms of public impact would be significantly smaller for this route than for the route through the town because of the effect of the population density on the consequence analysis. This agrees with the qualitative statement of Federated's risk consultant, Dr. Bercha.

The Board notes that Dr. Bercha suggested that the initiating event probability would be lower for the route through the town with its proposed third-party damage prevention measures than for the routes around the town. The Board questions this conclusion, given the relatively high level of construction activity which is likely to occur adjacent to the Federated right of way through the town over the 20-year period during which the line might be in HVP service. During the same period, the Board would not expect a great deal of construction activity would take place outside the town even if the route was only 1000 feet (305 m) from the current boundaries.

The Board also notes the suggestion from Qualico that locating the HVP pipeline 1000 feet (305 m) outside the town might allow sufficient time to implement an emergency evacuation whereas the proximity of proposed residential development adjacent to Federated's right of way through the town might not. The Board agrees with this point.

Having regard for the consequences should an accident occur on an HVP line through the town, due to third-party damage or otherwise, the Board believes that a route located so as to maintain an approximate 305-m (1000-foot) separation distance from the town is more appropriate than a route through the town. The route around the town would of course also have to have regard for the land use in the immediate vicinity. The Board believes that the incremental cost of relocating the pipeline around the town is warranted because it would significantly reduce any consequences to Morinville residents of a break. The Board draws this conclusion even though it recognizes that the risk associated with Federated's proposed route is small.

The Board also sees other possible benefits of locating the pipeline outside the town. There would be additional time available to implement an evacuation plan in the event of an emergency. Developers and the Town of Morinville would not have to be concerned with development restrictions or setback distances other than with Federated's existing right of way. There would be less chance of the marketability of the subdivisions adjacent to Federated's right of way being negatively affected. Finally, not locating an additional pipeline in the right of way, particularly as proposed with the additional depth of cover, might facilitate the installation of the many municipal service lines that will be required to develop the adjacent subdivisions.

A negative effect of rerouting the proposed line would be the disturbance of agricultural land along the 5.5-km (3.5-mile) long right of way during installation of the pipeline. With Federated's proposed reclamation procedures, however, the negative effect should be only temporary.

## 7 DECISION

The Board is prepared to approve Application 830394 by Federated Pipe Lines Ltd. to amend Pipeline Licences No. 114, 904, and 4956, subject to the successful completion of the inspection and testing program specified in section 4 of this report. Subsequent to this, the Board is prepared to issue a permit for the construction of the proposed pipelines for the Fort Saskatchewan to Namao section and the sections in the Swan Hills and Judy Creek areas.

The Board is not prepared to issue a permit for the construction of the new line through Morinville for the reasons outlined in section 6 of this report. The Board believes Federated should instead consider a route around the Town of Morinville that maintains a reasonable separation distance between the town boundary and the pipeline.

DATED at Calgary, Alberta on 17 November 1983

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy, P.Eng.
Vice Chairman

V. E. Bohme, P.Eng.
Board Member

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

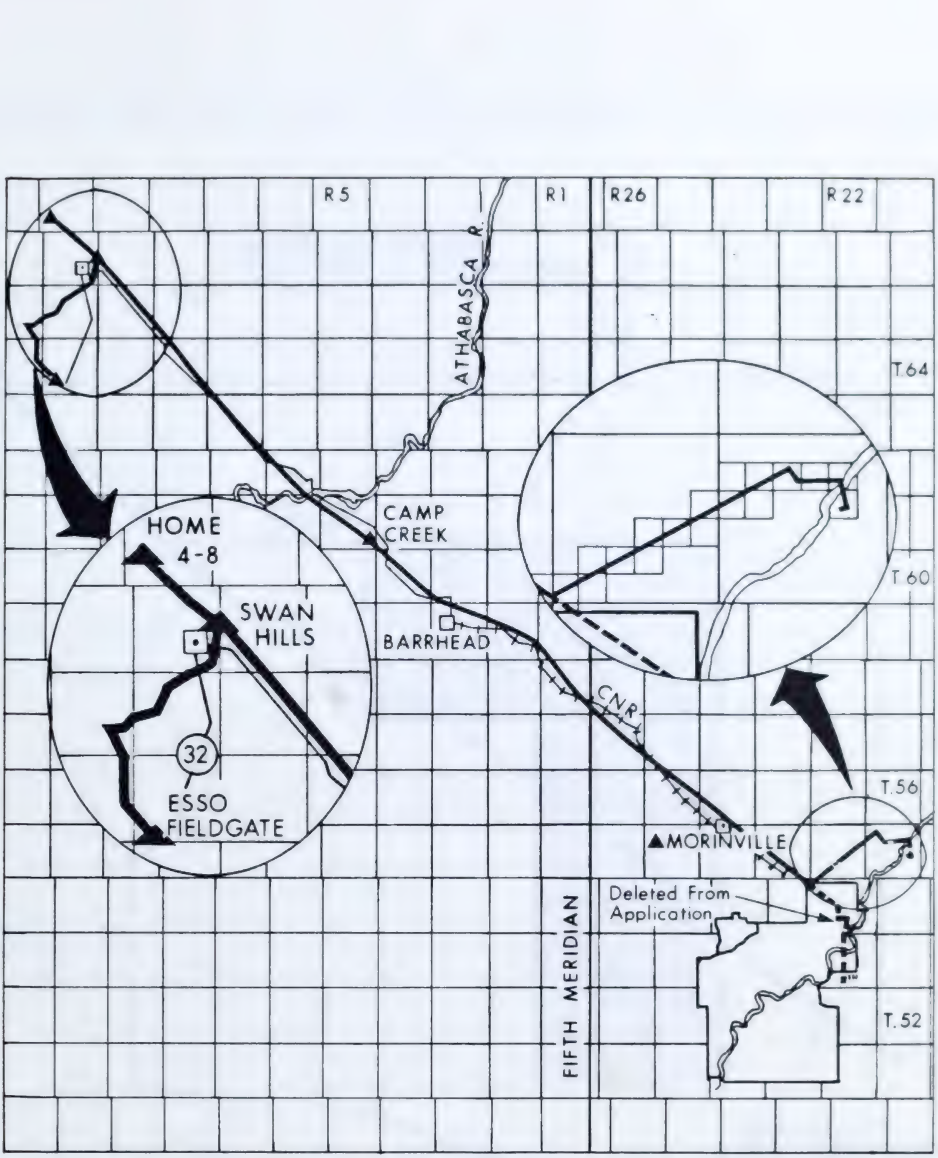


FIGURE 1 FEDERATED PIPE LINES LTD. PROPOSED HIGH VAPOUR PRESSURE PIPELINE FROM FORT SASKATCHEWAN TO SWAN HILLS AREA.

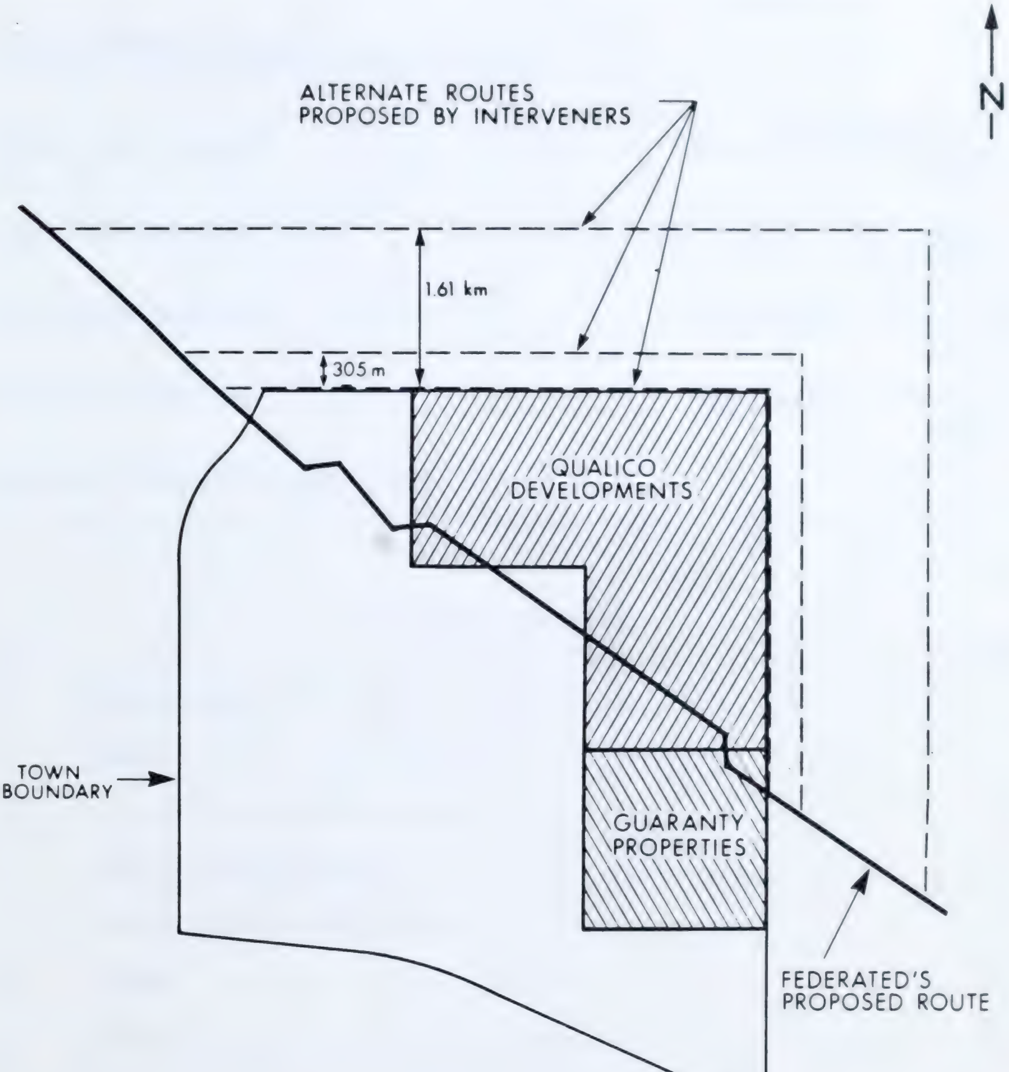


FIGURE 2 PROPOSED PIPELINE ROUTES THROUGH AND AROUND THE TOWN OF MORINVILLE.

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta



PETRO-CANADA INC.
HUDSON'S BAY OIL AND GAS COMPANY LIMITED

Decision D 83-29

GAS CYCLING SCHEMES — Applications 830567 and 830883

SOUR GAS PIPELINES — Applications 830836, 830873, and 831088

INJECTION PIPELINES — Applications 830874 and 831086

FUEL GAS PIPELINES — Applications 830875 and 831087

BRAZEAU RIVER-WEST PEMBINA AREA

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# 1 INTRODUCTION

## 1.1 Background

Hudson's Bay Oil and Gas Company Limited (HBOG) and Petro-Canada Inc. (Petro-Canada) have planned separate gas gathering/processing/cycling projects in the Brazeau River-West Pembina area. Figure 1 shows the proposed pipeline routes, the approved gas plants, and other geographical features of the area.

In ERCB Decision 81-36, issued in December 1981, the Board approved the HBOG gas processing plant.

HBOG subsequently filed pipeline applications in October 1981 to supply its plant with gas, after which the project was delayed indefinitely.

In January 1983, Petro-Canada proposed a gas processing scheme which proposed cycling of the Brazeau River Nisku F Pool (F Pool).

In March 1983, HBOG updated its pipeline applications to include a connection to the F Pool and requested a hearing.

Petro-Canada filed a gas cycling scheme application for the F Pool in June 1983.

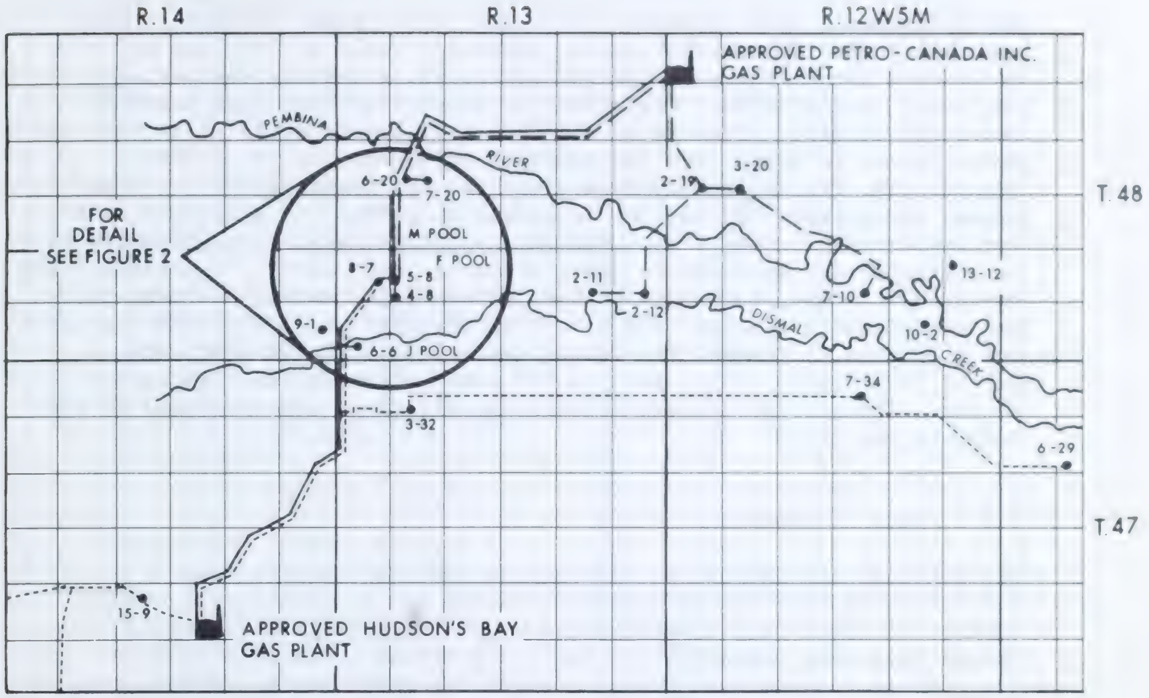
The Board considered HBOG's proposed sour gas, injection, and fuel gas pipelines at a hearing in June 1983. In ERCB Decision D 83-11, the Board approved the HBOG proposed gathering system, but deferred its decision to connect the F Pool because of economic, environmental, and conservation concerns associated with developing the pool. The concerns were mainly raised by Petro-Canada and other owners of F Pool gas who proposed cycling of the F Pool.

In July 1983, the Board considered the Petro-Canada gas processing scheme. In ERCB Decision D 83-20 the Board approved the proposed gas plant but deferred its decision regarding processing of F Pool production at the Petro-Canada plant until it considered, in detail, a gas cycling scheme for the F Pool.

Petro-Canada filed pipeline applications for its project in August 1983, and HBOG filed a competing F Pool gas cycling scheme application in September 1983. The Board considered the competing F Pool cycling schemes, the connection of the F Pool by HBOG, and the Petro-Canada proposed pipelines together at a hearing in November 1983.

## 1.2 Applications

At the hearing Petro-Canada and HBOG stated that the companies had reached interim production sharing agreement that would allow development of the F Pool to proceed. The basis of the agreement was that primary production from the pool would be shared and that both the Petro-Canada




LEGEND

H.B.O.G. PROPOSED PIPELINES
PETRO-CANADA PROPOSED PIPELINES
AMOCO PROPOSED PIPELINES

FIGURE 1 H.B.O.G., PETRO-CANADA, AND AMOCO PROPOSED PIPELINES.
**Brazeau River - West Pembina Area.**

and HBOG plants would process F Pool gas (a two-plant concept). Both applicants also agreed that a unit agreement would be in place prior to cycling of the F Pool and that the additional reservoir evaluation performed during primary depletion (to a reservoir pressure somewhat above the dewpoint pressure of the reservoir fluid) would allow HBOG and Petro-Canada to design the optimum cycling scheme for the F Pool. Accordingly, the applicants requested that the Board consider neither scheme as applied for, but rather consider approval in principle of a cycling scheme for the F Pool with the specific cycling requirements to be evaluated and approved by the Board at a later date. To implement the two-plant concept, Petro-Canada amended its pipeline applications to include pipelines to the HBOG 8-7-48-13 W5M (8-7) well while HBOG applied for pipelines to connect the Petro-Canada 4-8-48-13 W5M (4-8) and 5-8-48-13 W5M (5-8) wells and its 8-7 well to its approved gathering system. The gas cycling and pipeline applications are described in the following sections.

### 1.2.1 Cycling Schemes

Petro-Canada and HBOG filed independent applications pursuant to section 26 of the Oil and Gas Conservation Act respecting gas cycling schemes in the F Pool. Petro-Canada, on behalf of itself, Amoco Canada Petroleum Company Ltd. (Amoco), and Texaco Canada Resources Ltd. (Texaco), submitted Application 830567 proposing a two-well cycling scheme. The scheme would involve lean gas injection into the Petro-Canada/Amoco/Texaco 5-8 well and production from the Petro-Canada/Amoco/Texaco 4-8 well. Gas would be cycled at 141 thousand cubic metres per day ($10^3$ $m^3/d$) with all produced gas being processed at the approved Petro-Canada plant located at 4-31-48-12 W5M (4-31).

HBOG submitted Application 830883 proposing a three-well cycling scheme in which lean gas would be injected into the HBOG 8-7 well and produced from the 4-8 and 5-8 wells. Recoveries for different combinations of injection and producing wells were also evaluated in the application. Gas would be cycled at 282 x $10^3$ $m^3/d$ with HBOG processing the entire production at its West Pembina plant, or both Petro-Canada and HBOG processing their equity share of the gas at their respective plants.

Both parties requested that the Board approve in principle a cycling scheme for the F Pool and disregard the original applications with respect to the F Pool. The details would be adressed at a later date.

### 1.2.2 Pipeline Applications

Petro-Canada and HBOG applied pursuant to Part 4 of the Pipeline Act for permits to construct pipelines to gather sour gas from wells in the Brazeau River area for processing at their approved Brazeau River and West Pembina gas plants, respectively, to return residue gas for area gas cycling schemes, and to distribute fuel gas to field facilities. Details of the pipeline applications are set out below. Figures 1 and 2 show the proposed pipelines.

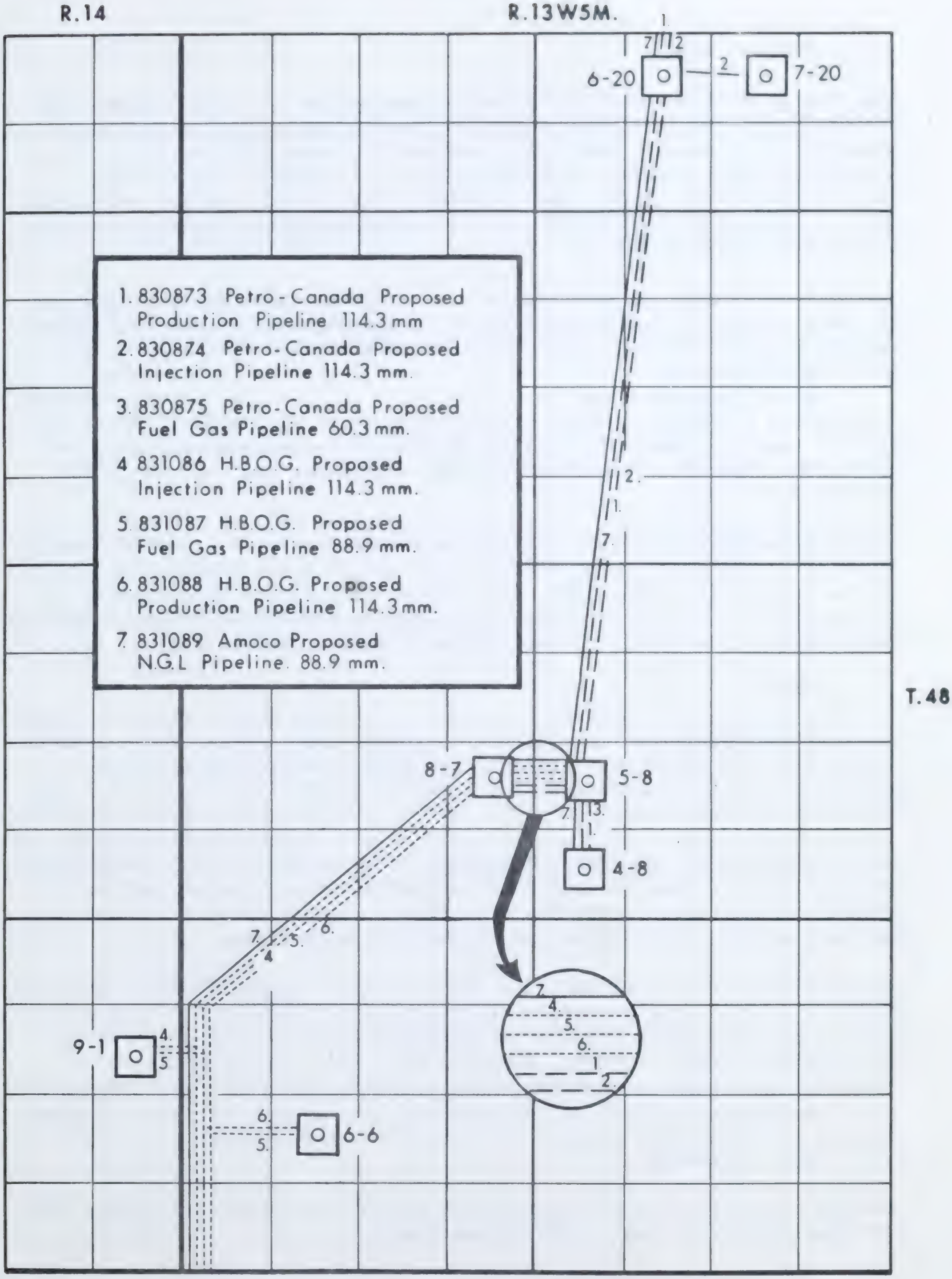



FIGURE 2 DETAIL OF PROPOSED PIPELINES.
Brazeau River - West Pembina Area.

Petro-Canada

Application 830836 was to construct approximately 16.16 kilometres (km) of 168.3- and 114.3-millimetre (mm) outside diameter (OD) pipeline to transport sour natural gas with a maximum hydrogen sulphide ($H_2S$) content of 188.8 mol/kmol from wells in Lsd 7-10-48-12 W5M (7-10), Lsd 3-20-48-13 W5M (3-20), Lsd 2-19-48-12 W5M (2-19), Lsd 2-11-48-13 W5M (2-11), and Lsd 2-12-48-12 W5M (2-12) to the gas plant tie-in in Lsd 13-30-48-12 W5M (13-30).

Application 830873, as amended, was to construct approximately 14.24 km of 168.3- and 114.3-mm OD pipeline to transport sour natural gas with a maximum $H_2S$ content of 6.8 mol/kmol from the 5-8 and 8-7 wells to the 13-30 plant tie-in.

Application 830874, as amended, was to construct approximately 14.13 km of 88.9- and 114.3-mm OD pipeline to transport sweet natural gas, for injection, from the 13-30 plant tie-in to wells in Lsd 7-20-48-13 W5M (7-20), 5-8, and 8-7.

Application 830875 was to construct approximately 16.54 km of 60.3-mm OD pipeline to transport sweet natural fuel gas from the 13-30 plant tie-in to the 2-19, 2-12, 2-11, 3-20, and 7-10 well sites and from tie-ins to the proposed injection pipelines (Application 830874) at the 6-20 and 5-8 well sites to the 6-20, 4-8, and 5-8 well sites, respectively.

HBOG

Application 831086 was to construct approximately 2.24 km of 114.3-mm OD pipeline to transport sweet natural gas from a connection with its approved injection pipeline in Lsd 13-6-48-13 W5M (13-6) to the 8-7 and 5-8 wells for injection.

Application 831087, including a portion of Application 820251 deferred by Decision D 83-11, was to construct approximately 2.20 km of 88.9-mm OD pipeline to transport sweet fuel gas from a connection with its approved fuel gas pipeline in 13-6 to the 8-7 and 5-8 well sites.

Application 831088, including a portion of Application 810924 deferred by Decision D 83-11, was to construct approximately 3.43 km of 168.3-, 114.3-, and 88.9-mm OD pipeline to transport sour natural gas with an $H_2S$ content of 252.0 mol/kmol from the 4-8, 5-8, and 8-7 wells to connect to its approved gas gathering system in Lsd 5-6-48-13 W5M.

### 1.2.3 Gas Processing

Matters concerning the processing of F Pool gas at the Petro-Canada and HBOG gas plants are dealt with in section 3.3.

## 1.3 Hearing

V. E. Bohme, P.Eng., C. J. Goodman, P.Eng., and J. A. Bray, P.Eng., heard the applications at a public hearing on 16 November 1983 in Calgary, Alberta.

### THOSE WHO APPEARED AT THE HEARING

| Principals and Representatives (Abbreviations used in Report) | Witnesses |
|---|---|
| Petro-Canada Inc.<br>(Petro-Canada)<br>D. O. Sabey, Q.C.<br>B. K. O'Ferrall | F. J. Bagley, P.Eng.<br>P. H. Verity, P.Eng.<br>G. A. Reitzel, P.Eng.<br>T. H. Sole, C.E.T.<br>Dr. L. Lewis |
| Hudson's Bay Oil and Gas Company Limited<br>(HBOG)<br>C. K. Yates | J. R. Moore, P.Eng.<br>Dr. G. R. Besserer, P.Eng. |
| Texaco Canada Resources Ltd.<br>(Texaco)<br>R. Blumell | |
| Amoco Canada Petroleum Ltd.<br>(Amoco)<br>A. G. Kruse | J. D. Griffith, P.Eng.<br>R. B. Arnold, P.Eng. |
| Her Majesty the Queen<br>in the Right of Alberta<br>(Crown)<br>T. Bossenberry | |
| Energy Resources Conservation Board staff<br>R. Cox, E.I.T.<br>H. Knox, P.Eng. | |

The Board issued its decision at the conclusion of the hearing. This report details the reasons for the decision and sets out conditions concerning the operation of the F Pool and several Carbonate Bank wells.

## 2 ISSUES

The Board believes the issues respecting the applications can be grouped as follows:

## 3 CYCLING SCHEME APPLICATIONS

### 3.1 Need for F Pool Cycling

HBOG stated that the F Pool is a retrograde condensate reservoir containing substantial volumes of sales gas, and propane, butane, and pentanes-plus liquids. HBOG contended that production of this reservoir below the dewpoint pressure of the system would cause these hydrocarbon liquids to condense in the reservoir, rendering them immobile. It stated that production of this reservoir through a scheme of lean gas injection at a pressure above the dewpoint pressure of the reservoir fluid would permit maximum recovery of the hydrocarbon liquids that would otherwise be lost due to retrograde condensation.

HBOG noted that the reservoir temperature is very close to the critical temperature of the reservoir fluid. Further, slight errors in the sampling technique or determination of reservoir temperature could result in the fluid being defined as a volatile oil rather than retrograde condensate. However, HBOG contended that if the reservoir fluid was determined to be a volatile oil, a miscible flood of lean high pressure gas injected at a pressure above the minimum miscibility pressure would result in recoveries similar to that of a retrograde condensate cycling scheme. HBOG stated that it and other F Pool owners are committed to finalizing a unit operating agreement prior to cycling.

Petro-Canada agreed with the HBOG interpretation of the reservoir fluid being a retrograde condensate which is near its critical temperature. Petro-Canada further agreed that the implementation of a gas cycling scheme is necessary to maximize the recovery of the pool's hydrocarbon resources and confirmed that all parties are committed to finalizing a unit agreement.

Amoco supported a cycling scheme for the F Pool, subject to submission of the necessary technical information. Texaco also supported a cycling scheme for the pool.

The Board concurs with both HBOG and Petro-Canada that the reservoir fluid appears to be a retrograde condensate very near its critical temperature and it agrees that a cycling scheme of lean gas injection above the reservoir fluid dewpoint pressure is needed to maximize hydrocarbon recovery from the pool. It notes the possibility that the reservoir fluid may be a volatile oil, in which case a scheme of lean gas injection could create a miscible flood resulting in recovery similar to a retrograde condensate cycling system.

The Board believes that competitive cycling operations in the F Pool could result in hydrocarbon recovery less than from a joint cycling scheme but notes that both applicants are committed to finalizing a unit agreement for the pool prior to the commencement of cycling. The Board is therefore prepared to approve in principle a gas cycling scheme for the F Pool subject to a unitization agreement being finalized.

## 3.2 Primary Depletion Procedure

HBOG estimated the gas in place of the F Pool to be 698 million cubic metres ($10^6$ $m^3$) and noted that there is a discrepancy between its estimate and Petro-Canada's estimate of 756 x $10^6$ $m^3$. As these figures represent material balance estimates from a short production period, HBOG stated that primary depletion of the reservoir to a pressure above the dewpoint pressure would enable the extent of the reserves to be better determined. HBOG stated that the interim production agreement reached between all parties would allow for primary depletion without a unit agreement, but noted that all parties are committed to completing a unit agreement prior to cycling of the F Pool.

HBOG interpreted the dewpoint pressure of the reservoir fluid to be between Petro-Canada's estimate of 31 600 kilopascals (kPa) and its own estimate of 32 500 kPa. HBOG stated that primary depletion to an average reservoir pressure of 36 000 kPa should provide further information regarding the reservoir fluid classification and the extent of reserves. This information would be pooled to enable all parties to determine the optimum depletion strategy for the pool. HBOG stated that a primary depletion pressure limit of 36 000 kPa would also be adequate to achieve a miscibility pressure and maximize recovery in the event of the fluid being a volatile oil.

HBOG suggested that, based on a primary depletion rate of 141 x $10^3$ $m^3/d$, a program of pressure monitoring requiring a build-up test every 6 months of production would be adequate to ensure that the reservoir pressure did not drop below 36 000 kPa. It further suggested that a program of pressure monitoring requiring tests based on production withdrawal intervals could allow for flexibility between a production rate of 141 x $10^3$ $m^3/d$ and 282 x $10^3$ $m^3/d$.

Petro-Canada agreed that primary depletion of the F Pool to 36 000 kPa should provide sufficient information to confirm the fluid classification, determine the extent of reserves, and the optimum depletion strategy. Petro-Canada also agreed that the minimum pressure of 36 000 kPa would be sufficient to avoid loss of hydrocarbon liquid recovery through retrograde condensation.

Petro-Canada stated that it generally conducts quarterly pressure surveys on pools in the area that it operates. Petro-Canada would be prepared to implement the same program on the F Pool to ensure that the initial primary depletion does not reduce the reservoir pressure below 36 000 kPa.

Amoco and Texaco, as working interest owners of the Petro-Canada operated wells, supported the HBOG and Petro-Canada primary depletion strategy.

The Board is satisfied that additional information regarding the reserves and nature of the reservoir fluid can be acquired through primary depletion to an average reservoir pressure of 36 000 kPa. The Board believes that this minimum pressure should be adequate to avoid loss of liquid recovery due to retrograde condensation. In the event that the fluid is determined to be a volatile oil, however, the Board would require that the appropriate tests be performed to determine the miscibility pressure for injection of the proposed lean gas.

The Board believes that the reservoir pressure should not be permitted to fall below 36 000 kPa during primary depletion. It also believes that a pressure monitoring program conducted quarterly as proposed by Petro-Canada will ensure that the pool pressure will not fall below the minimum of 36 000 kPa at either of the production rates suggested.

### 3.3 F Pool Gas Processing

Petro-Canada stated that its agreement with HBOG for sharing of primary F Pool production was based on processing the gas at both the HBOG and Petro-Canada plants. It noted that to implement the two-plant concept some duplication of pipelines would be required, but stated that processing at two plants would result in economic, orderly, and efficient development of the F Pool. Some of the benefits it noted were the availability of spare compression capacity at its 4-31 plant, the early on-stream date of the HBOG plant, optimum loading of both plants while

effecting the optimum pool cycling rate, less expensive residue gas for injection, and the maintenance of proprietary gas rights. Additionally, it stated the incremental effects on the environment of processing the F Pool production at both plants would not be significant.

In addition to the advantages of the two-plant concept cited by Petro-Canada, HBOG indicated that if processing were to occur at only one plant then the other plant would have significant unused capacity (costing about $6 million). It also stated that there would be no negative effects on F Pool recovery because the pool cycling operating costs would be about the same at both plants. It noted that the two plants would provide the ultimate in operating flexibility because the pool production could be diverted to either plant, for example during plant turnaround periods. While it said the incremental costs to tie in the F Pool to both plants would be about $400 000, it believed the benefits outweighed the costs. It also noted that by constructing its proposed pipelines with the proposed Amoco natural gas liquids (NGL) pipeline there would be reduced overall environmental impacts to the area from the necessary pipelines.

The Board agrees with the applicants that the operating advantages afforded by processing F Pool production at both the Petro-Canada and HBOG plants are significant. While the two plant concept would result in some duplication of pipelines, the Board is satisfied the two-plant concept is, in this instance, in the public interest because both plants would operate at their design capacities, equity is maintained, and the overall pool recovery would be the same. Additionally, both plants afford similar environmental benefits in terms of sulphur recovery. Accordingly the Board believes that processing of F Pool gas at both plants is appropriate and should be allowed.

The Board notes that both Amoco and Texaco supported the two-plant concept.

## 4 PIPELINE APPLICATIONS

### 4.1 Petro-Canada

#### 4.1.1 Need

Petro-Canada stated that its proposed pipelines are an integral part of its planned development in the Brazeau River area. Specifically, with the approval of its gas plant, pipelines would be needed to transport production from, and return residue gas to, the F and M condensate pools for gas cyling. Pipelines would also be needed to transport production from Carbonate Bank wells in the area to further evaluate and delineate the reservoir.

Respecting duplicate pipelines to the F Pool by both Petro-Canada and HBOG, Petro-Canada stated that the advantages of the two-plant concept outweighed the costs of facility duplication. It cited, in particular, overall reduced environmental impacts from concurrent construction of the Petro-Canada and HBOG pipelines to the F Pool with a proposed Amoco NGL pipeline (see Figure 1) to the HBOG plant, as well as significant cost savings. Petro-Canada added that the cost of the duplication of pipeline facilities was less than the cost of the compression facilities that would be required at the HBOG West Pembina plant under a one-plant processing scheme. Petro-Canada urged the Board to accept the two-plant concept and to approve promptly not only its proposed pipelines to the F Pool, but also the HBOG pipelines to realize the aforementioned benefits.

Concerning the pipeline application amendments it made at the hearing, Petro-Canada said that extending its production and injection pipelines to the 8-7 well site was part of its interim agreement with HBOG in keeping with the two-plant concept. It stated that its application amendments and HBOG's applications for pipelines within the F Pool (see Figure 2 enlargement) represented the maximum number of pipelines that could be needed to implement the two-plant concept. In making its amendments it noted that some of the applied-for lines might not be built as the details of the joint cycling scheme were finalized. Nonetheless, it requested approval of all the proposed pipelines between 8-7, 5-8, and 4-8 to allow the F Pool negotiations with HBOG to continue. Petro-Canada concluded that the advantages to the two-plant concept outweighed the expected duplication of facilities, and therefore represented economic and orderly development of the area.

HBOG, Amoco, and Texaco supported the Petro-Canada proposed Carbonate Bank pipelines.

Concerning pipelines to the F Pool, HBOG said that both the Petro-Canada and HBOG proposed pipelines were needed to develop the pool. HBOG cited the environmental and economic benefits of common construction with Amoco.

Amoco and Texaco supported the proposed F Pool pipelines.

The Board believes that the Petro-Canada pipelines are needed to supply gas to the Petro-Canada gas plant. It agrees that production from the Carbonate Bank wells will allow the reservoir to be further evaluated and that the pipelines to the M and F pools will allow gas cycling to proceed. Respecting the additional portions of pipeline applied for at the hearing by Petro-Canada, the Board believes there is a potential need for those pipelines as part of a cycling scheme for the F Pool.

### 4.1.2 Route Selection

Petro-Canada stated that its preferred pipeline routes were selected to limit east-west linear disturbance through the Critical Wildlife Area

between the Pembina River and Dismal Creek, respectively. Petro-Canada noted that 23 km of the total length of 31 km of its pipeline would follow existing disturbances and that it would parallel the proposed Amoco pipeline for some 14 km. In comparing its preferred routes with a rejected alternative through the Critical Wildlife Area, it stated that nothwithstanding the required three crossings of the Pembina River associated with its preferred route, the overall environmental effects would be less. It believed this to be the case even if access to an east-west route through the Critical Wildlife Area could be restricted. Petro-Canada stated that its routing has the support of government agencies (Alberta Environment) and it minimizes disturbances in the critical wildlife region between the Pembina River and Dismal Creek.

Concerning questions about Pembina River slope stability along a portion of the Carbonate Bank pipeline, Petro-Canada stated that its routing met land conservation guideline requirements for pipelines in the vicinity of water courses and that the area had been reviewed by a geotechnical consultant.

The Board notes that the majority of Petro-Canada's proposed pipeline routes follow existing linear disturbances and that right of way sharing with Amoco is proposed. Concerning the proposed route of the pipelines to the M and F pools, it believes that common construction with Amoco can significantly reduce area environmental impacts. It is satisfied that the proposed routes are appropriate to transport gas to the gas plant with due regard for the environment.

### 4.2 HBOG Pipelines to Connect the F Pool

#### 4.2.1 Need

HBOG stated that the two-plant concept agreed to by Petro-Canada et al, and HBOG, depended on Board approval of pipelines from its gathering system to the F Pool. It said that its gas plant design capacity included about $140 \times 10^3$ $m^3/d$ for F Pool cycling and that the gas would be required for its planned March 1984 plant start-up.

HBOG contended that the incremental costs of pipelines from both the Petro-Canada and HBOG plants were insignificant when compared to the advantages. Those cited by HBOG included operating flexibility, overall reduced environmental impacts, and significant cost savings from common construction with the Amoco NGL pipeline.

HBOG agreed with Petro-Canada that all of the pipelines within the F Pool (see Figure 2) might not be required, but requested approval to allow F Pool depletion plan and unitization negotiations to continue unrestricted.

The Board accepts that the deferred HBOG pipeline from 9-1 to 8-7 (Decision D 83-11), the extended production and fuel gas pipelines (from 8-7 to 5-8 to 4-8, and 8-7 to 5-8, respectively), and the proposed injection pipeline (from 9-1 to 8-7 to 5-8) could be needed to cycle F Pool gas, in keeping with the two-plant concept. It notes that Petro-Canada, Amoco, and Texaco supported HBOG's proposed pipelines.

## 5 CARBONATE BANK CONSERVATION

HBOG referred to a condition imposed on production from the 7-34 well of the Carbonate Bank as described in Board Decision D 83-11. The condition allows production from the well, subject to HBOG undertaking to establish the dewpoint pressure of the fluid produced from the 7-34 well. The condition further requires that the well not be produced below this dewpoint pressure prior to establishing the optimum depletion scheme for the conservation of hydrocarbons. HBOG requested that a similar condition be applied to the 7-10 and 3-20 wells licensed to Petro-Canada and Amoco because of pressure communication between these wells and its 7-34 well and the potential for future cycling schemes involving these and other Carbonate Bank wells.

Petro-Canada stated that it would not object to a condition similar to that imposed on the 7-34 well being imposed on the 7-10 and 3-20 wells. Petro-Canada indicated that reservoirs to be cycled should not be produced below the dewpoint pressure prior to the implementation of pressure maintenance. Petro-Canada notes, however, that some production must be taken from these wells to ensure that the appropriate reservoir interpretation is obtained.

Amoco stated that its study of the area has shown that cycling appears feasible in the eastern portion of the Carbonate Bank, referring to the 10-2, 7-10, 13-12, and 7-34 wells. In response to HBOG's request for a condition on production of the 7-10 well, Amoco did not object as the 7-10 would definitely be included in a cycling scheme.

With respect to the western portion of the Carbonate Bank, referring to the 2-12, 2-19, and 3-20 wells, Amoco stated that the feasibility of cycling is not as definite as the eastern portion. Tenuous continuity between wells and a lack of definitive fluid data currently precludes a positive decision on cycling. Amoco stated that it would require extended production to determine the cycling feasibility and hoped that the necessary information could be obtained prior to reaching the dewpoint pressure. However, Amoco stated that the requirements for additional data could override the normal concerns about the dewpoint. Although Amoco would prefer that no condition be placed on production from the 3-20 well, based on the precedent set by conditioning the 7-34 well, it agreed that it would be consistent to condition the 3-20 well. However, it suggested that it would be more appropriate to discuss the situation with Board staff and arrive at a decision when the production data is available.

The Board notes that, although the 3-20 well is subject to tenuous communication with other wells, there is potential for additional drilling in the vicinity. The Board suggests that additional drilling could conceivably lead to a separate cycling scheme for the 3-20 and additional wells.

Concerning the entire Carbonate Bank, the Board recognizes a potential for the cycling of gas, and further notes that some production is required from these wells to properly evaluate the feasibility of cycling. The Board realizes that, although undesirable in pools which may be cycled, circumstances may warrant production below the dewpoint pressure in order to determine the appropriate depletion strategy. The Board is prepared to allow production from the 7-10 and 3-20 wells subject to the operators undertaking to establish the dewpoint pressure of the reservoir fluid and not to produce below that pressure prior to establishing either the optimum depletion strategy for hydrocarbon recovery or justification for continued production.

## 6 SUMMARY

The Board believes that a cycling scheme for the F Pool will be required to maximize hydrocarbon recovery from the pool. It is satisfied that primary depletion to a reservoir pressure of about 36 000 kPa will allow HBOG and Petro-Canada to design an optimum unitized cycling scheme, and that with the approval of the two-plant processing concept the area's reserves will be properly developed. It agrees with the applicants that the benefits of the two-plant connection, taking into account the reduced environmental effects of proposed concurrent pipeline construction with Amoco, outweigh the costs.

It believes the pipeline routes selected by Petro-Canada will have less impact on the area overall than alternate "east-west" routes between the Pembina River and Dismal Creek.

The Board believes the Carbonate Bank pipelines are needed to evaluate and delineate the reservoir. However, having regard for the potential for gas cycling in the Carbonate Bank, it believes a condition limiting production to a pressure above the dewpoint pressure to be appropriate for the 7-10 and 3-20 wells.

## 7 DECISION

Processing of Brazeau River Nisku F Pool production at the HBOG West Pembina and Petro-Canada Brazeau River gas plants is approved. Primary production may proceed, subject to quarterly pressure measurements that will ensure production is not taken at a reservoir pressure of less than 36 000 kPa.

The Board approves in principle a cycling scheme for the Brazeau River Nisku F Pool. The necessary cycling approval will be issued by the Board's Gas Department after an acceptable cycling application, pursuant to section 26 of the Oil and Gas Conservation Act, is made by the unit operator of the pool.

The Board approves Applications 830836 and 830875 and amended Applications 830873 and 830874 by Petro-Canada Inc., and Applications 831086, 831087, and 831088 by HBOG, subject to receipt of the approval of the Minister of the Environment respecting environmental matters.

ISSUED at Calgary, Alberta on 7 December 1983.

ENERGY RESOURCES CONSERVATION BOARD

V. E. Bohme
V. E. Bohme, P.Eng.
Board Member

C. J. Goodman
C. J. Goodman, P.Eng.
Board Member

J. A. Bray
J. A. Bray, P.Eng.
Acting Board Member

ERCB DECISION D 83-C

# MERCOAL COAL PROJECT

## DECISION ON AN APPLICATION BY MERCOAL MINERALS LTD.

APRIL 1983

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA, CANADA

ENERGY RESOURCES CONSERVATION BOARD
DECISION REPORT SERIES

Report D 83-C concerns

Application No. 820385 made by
Mercoal Minerals Ltd. under sections 10(b)
and 23 of the Coal Conservation Act

Report D 83-C published April 1983

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## SYMBOLS AND EQUIVALENTS

| | |
|---|---|
| \$ | dollars |
| M | mega (million) |
| Mta | mega tonnes per annum |
| cm | centimetre (1 cm equals 0.3937 inches) |
| m | metre (1 m equals 3.2808 feet) |
| km | kilometre (1 km equals 0.6214 miles) |
| ha | hectare (1 ha equals 2.4710 acres) |
| t | tonne (1 t equals 2204.62 pounds) |
| t/h | tonnes per hour |
| $m^3/h$ | cubic metres per hour |
| BCM/t | bank cubic metres per tonne |

# 1 BACKGROUND

## 1.1 THE APPLICATION AND APPLICANT

This report relates to an application by Mercoal Minerals Ltd. for a permit pursuant to Part 4, Section 10 (b) of the Coal Conservation Act to develop a surface coal mine and an approval pursuant to Part 5, Section 23 of the Coal Conservation Act to construct a coal processing plant and auxilliary facilities, to be located in Townships 47, 48 and 49, Ranges 20, 21, 22 and 23, all west of the 5th Meridian.

The applicant, Mercoal Minerals Ltd. (MML), is a wholly owned subsidiary of Manalta Coal Ltd., an Alberta based Canadian company. The applicant proposed to develop a mine to produce two million tonnes per year of clean coal as a joint venture with Idemitsu Kosan Co. Ltd. (Idemitsu), a Japanese energy company. The applicant would be the operator and majority owner, but Idemitsu would market at least 50 per cent of the production and have the right to earn up to a 20 per cent equity interest in the project. The applicant would be responsible for finding markets for the other 50 per cent of the production.

The Board received some twelve interventions from local residents and others who would be directly affected by the proposed development or have a bona fide interest in it.

## 1.2 THE HEARING: PARTICIPANTS

A public hearing of the application was held before the Energy Resources Conservation Board (ERCB or Board) from 2 to 4 November 1982 in Hinton, Alberta, before the sitting panel of N. Berkowitz, P. Eng., (Chairman) N. Strom, P. Eng., and F. J. Mink, P. Eng., (acting Board member).

Those appearing at the hearing are listed in Table 1, together with their affiliation.

The applicant spoke to the application through three panels of witnesses, which respectively dealt with the technical, environmental and socio-economic aspects of the proposed development.

Interveners did not generally oppose the proposed development, but commonly conditioned their support on resolution of specific concerns.

TABLE 1 PARTICIPANTS AT THE HEARING

| Principals and Representatives (Abbreviations Used in Report) | Witnesses |
|---|---|
| Mercoal Minerals Ltd. (MML) | |
| A. L. McLarty | R. N. Dalby, P. Eng. |
| R. J. Hall | G. D. Chapel, P. Eng. |
| | R. M. Shaneman |
| | D. J. Passfield |
| | P. S. W. Graham |
| | Dr. F. Worthington, P. Eng. |
| | B. Martens, P. Biol. |
| | R. Crysler, P. Eng. |
| | Dr. W. R. Dempster |
| | Dr. K. O. Higginbotham |
| | M. Strong |
| | Dr. H. Harries |
| Amelia Spanach | |
| D. B. Mason, Q.C. | |
| J. D. Thompson | |
| Hazel A. Tymofichuk | Hazel A. Tymofichuk |
| Town of Hinton | |
| D. W. Bartley | D. W. Bartley |
| L. Stadnick | |
| G. Tocher | |
| Town of Hinton, Economic Development Committee (HEDC) | |
| M. Dery | |
| Hinton and District Chamber of Commerce (HDCC) | |
| Barbara Hollup | Barbara Hollup |
| Town of Edson | |
| E. G. Hicks | |
| Yellowhead Regional Planning Commission (YRPC) | |
| P. Steen | P. Steen |
| | N. Connelly |

TABLE 1 PARTICIPANTS AT THE HEARING

| Principals and Representatives (Abbreviations Used in Report) | Witnesses |
|---|---|
| Esso Resources Canada Ltd. | |
| D. C. Parker | |
| Dentherm Resources Ltd. | |
| D. Fawcett, P. Eng. | |
| Smallboy's Camp, Hinton Metis Local 177, and Marlboro Local (Native Communities) | |
| Lorraine Sinclair | Lorraine Sinclair<br>Lorna Nixdorf |
| The Province of Alberta (The Crown) | |
| L. Brocke, P.Ag. | |
| T. Jantzie | |
| R. Millson | |
| R. L. Stone | |
| A. R. Watson | |
| Energy Resources Conservation Board (Board Staff) | |
| R. G. Paterson, P. Eng. | |
| K. Jamil, P. Eng. | |
| K. Johnston | |
| K. J. Bahadur | |
| M. J. Bruni | |

By prior agreement the Board accepted St. Regis' evidence submitted at the McLeod River Project hearing. A written intervention was also received from Mr. O. Weber on behalf of some concerned summer cottage leaseholders in the hamlet of Mercoal, but no one was present to speak to it.

## 1.3 OUTLINE OF THE PROPOSED PROJECT

The applicant proposes to develop a surface coal mining operation and to construct a coal processing plant and auxilliary facilities in the vicinity of the old Mercoal townsite, in the Coal Branch Area (Figure 1). The market product of the mine would be approximately two million clean tonnes of high volatile "C" bituminous thermal coal anually (2 Mta), destined for export market.

The proposed surface mine coal leases are divided into two blocks: Mercoal East and Mercoal West. Between the East and West blocks is a utility-transportation corridor, which accommodates Highway 40, the Canadian National Railway Coal Branch rail line, power lines and a sour gas pipeline. The processing plant, tailings dam and associated facilities would be located in the north-west part of the Mercoal East block.

Mining would commence in 1985 after an approximately two-year construction period, and be a conventional truck/shovel operation, with progressive back filling of mined-out areas. Mining would begin at the north-west corner of the Mercoal East block and proceed continuously to the south-east. Raw coal would be mined at an annual rate of approximately 3 Mta raw coal for a yield of 2 Mta of clean coal. It is anticipated that the operational life of the Mercoal East block would be in excess of 25 years, and there would be a three-year overlap period between the final coal removal in Mercoal East and the initial development activity in Mercoal West block.

Mercoal West block is located 4.5 kilometres northwest of the Canadian National Railway branch line and Highway 40. It would be necessary to construct a utility-transportation corridor from the processing plant site in Mercoal East to the south-east corner of the Mercoal West block. The conceptual development plan for Mercoal West proposes mining to proceed from the east end of the block (closest to the mine service facilities and

processing plant complex) and progress north-west, until surface mineable coal reserves are exhausted. Preliminary indications are that there are 10 to 15 years of surface mineable reserves in the West block. Further coal exploration programs are anticipated to increase this figure.

Raw coal from the mine would be hauled by trucks to the coal processing plant which by a system of screens, heavy media separation, and continuous belt presses, would produce clean coal and refuse. Some of the clean coal would be utilized in the coal-fired thermal dryer, and the refuse would go to a temporary storage bin for eventual disposal as mine backfill.

Make-up water for the plant would be obtained from a fresh water pond to be fed by mine dewatering wells and mine pumps. If necessary, some water would also be drawn from the McLeod River during times of high water flow. Other supporting facilities would include a tailings pond and an emergency clean-coal stockpile area.

Clean coal would be conveyed by a covered conveyor to two storage silos. The silos would then feed, via another covered conveyor, to an overtrack loadout silo, which would load the unit trains.

Electric power for the project would be supplied by TransAlta Utilities Corporation by the approved[1] 138 kV line which would follow the existing utility/transportarion corridor near the Mercoal townsite. The line is scheduled to be commissioned in early 1984.

Construction phase activities would support a peak work force of approximately 500. The workforce for the operating phase is estimated to be 340 in the first year, but rise to 430 in the second, and approximately 600 in the third year, after which the project is expected to operate at full capacity.

---

1 Board Permit and Licence No. CP 81-57, issued 7 December 1981

The entire project lease area lies within the St. Regis (Alberta) Ltd. Forest Management Agreement (FMA) area. The applicant's primary reclamation objective is to return the land disturbed by mining and associated activities to a productive state equal to that which existed prior to mining activities. This would involve reclamation of most of the disturbed land to commercial forestry with lodgepole pine and white spruce as principal species. Wildlife habitat and/or recreation areas would be established in those areas unsuitable for commercial forestry operations.

While the project lease area can be reached from Hinton by Provincial Highway 40, the travel distance and time is considered excessive. The applicant proposes that a new access road from Hinton to Mercoal be constructed by the Provincial Government in order to reduce travel time for the Mercoal mine workforce as well as provide better access for other resource development projects in the area.

The coal output of the project is expected to be sold entirely in export markets. Idemitsu has conditionally agreed to take 50 per cent, 1 Mta, for sale in Japan and negotiations are in progress with other Pacific Rim and Western European interests for sale of the remaining 50 per cent.

## 1.4 THE ISSUES

The Board considers the issues and concerns raised by the application to be:

- the design and layout of the mine, including

  - the extent and mineability of the coal reserves
  - the mine plan and inclusion of the West block
  - economic stripping ratio and mining depths
  - mining of the third party crown coal lease;

- the coal processing plant including

  - design factors
  - tailings pond capacity and tailings management
  - water supply;

- land-use conflicts;

- the suitability of the conceptual development and reclamation plans, and reclamation test plot construction schedule;

- social matters;

- economic considerations.

# 2 TECHNICAL MATTERS

## 2.1 DESIGN AND LAYOUT OF THE MINE

### 2.1.1 The Extent and Mineability of the Coal Reserves

The Mercoal coal deposits are of Paleocene age, being equivalent to the Scollard Member (Ardley coal zone) found in the Alberta plains. The geology of the area is largely determined by a large syncline-anticline pair composed of the Entrance syncline and the Prairie Creek anticline. The project area lies on the west limb of the syncline, and the beds dip north-east from a low of 23° to a high of 69°, averaging 31° in the Mercoal East block and 53° in the Mercoal West block.

The Coalspur beds, which contain the coal bearing sequence, present four major seams in the area, of which three, namely the Val d'Or, Silkstone and Mynheer seams, are considered mineable. The interseam materials are mainly comprised of sandstones with thin interbedded siltstones and mudstones. Seam partings consist mostly of carbonaceous mudstones, bentonite and tuffs.

The applicant's estimate of in-situ coal reserves for the combined East and West blocks of the project is approximately 809 Mt. This estimate is based on the total quantity of coal occurring between the seam subcrop and a maximum depth limit of 750m, an arbitrary maximum limit to underground mining. Of the total coal reserves, approximately 120 Mt is considered amenable to surface mining and the remaining 689 Mt is present at depths which can be reached by the underground mining methods. A summary of in-situ coal reserves is shown on Table 2.

MML recognized the need for, and would conduct, further drilling and exploration work for better definition of coal reserves, namely:

- in the East block, south of line 53, to confirm the geological interpretation and ascertain its mineability;

- in the West block for all seams but especially the Silkstone and Mynheer seams in order to bring West block area coal reserves into the proven category.

The Board generally concurs with the applicant's geological interpretations. Possible difficulties are foreseen with the structure south of line 53 in the East block, but judgement must be reserved until drilling and exploration work in the area have been completed. Similarly, geological information for the West block is minimal, and a substantial increase in the coal reserves is anticipated once the area is fully explored. The Board therefore considers the applicant's in-situ coal reserves estimate for the West block as only a preliminary estimate.

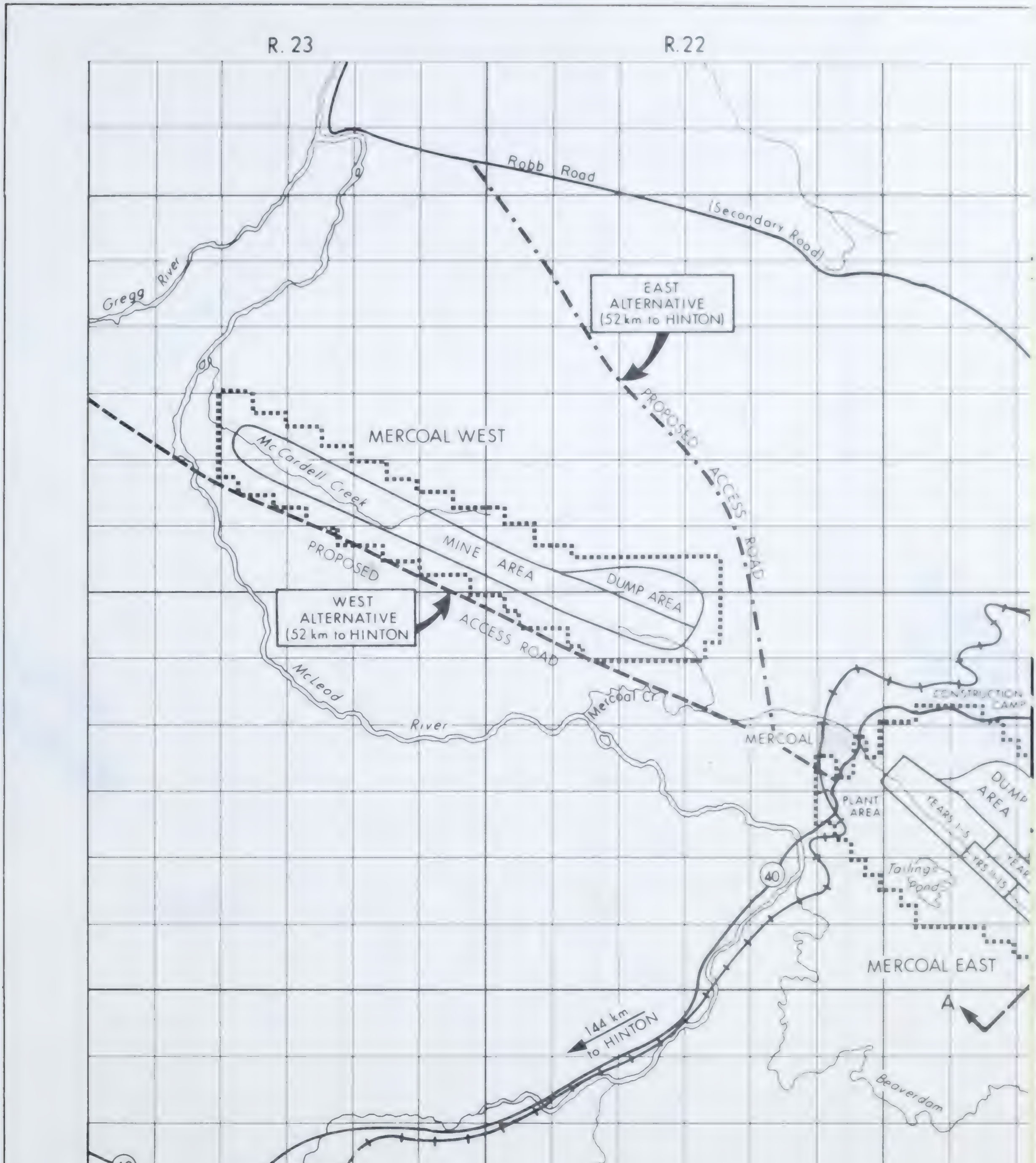
TABLE 2

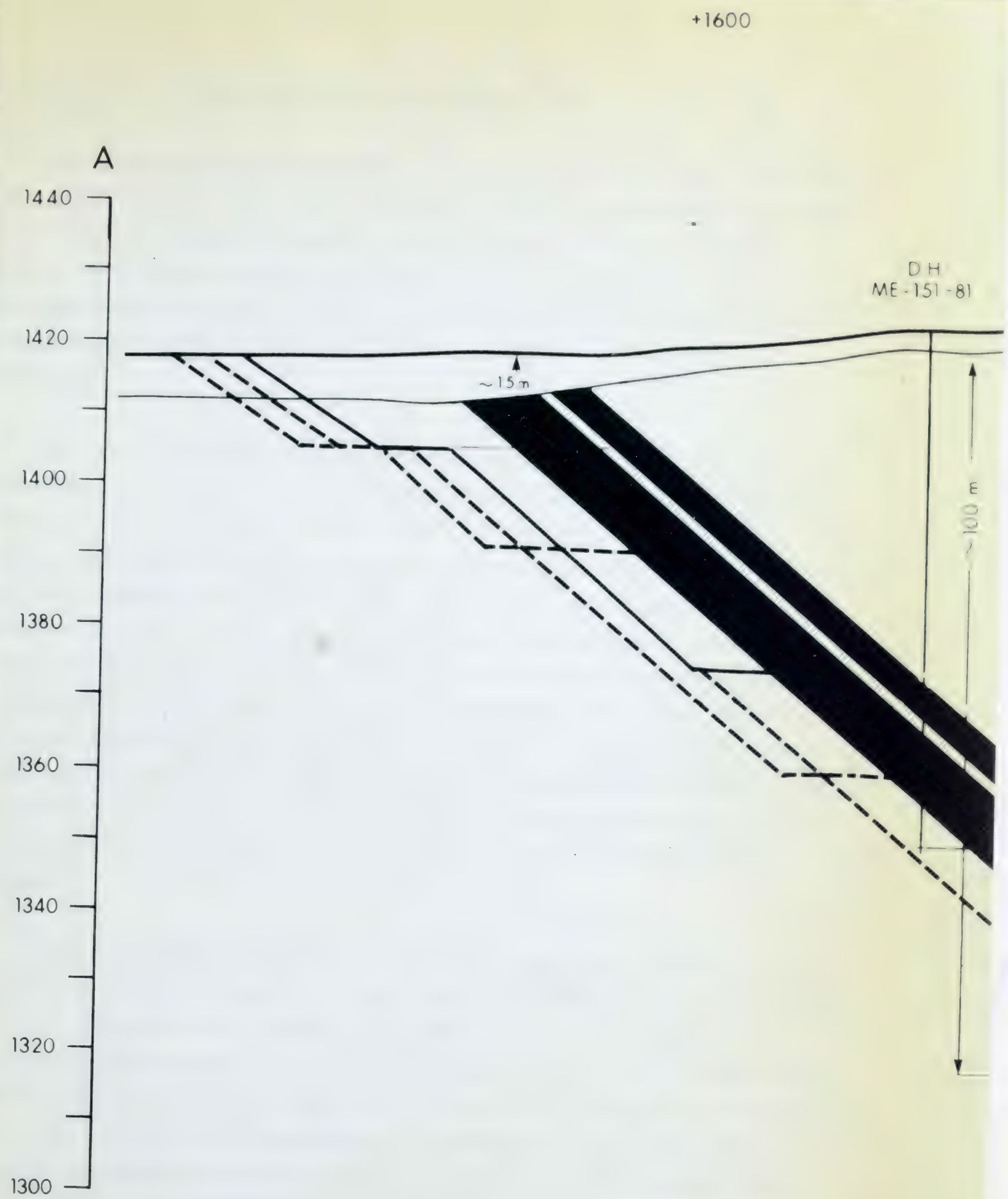
IN-SITU COAL RESERVES SUMMARY

| | Amenable to Surface Mining | | Amenable to Underground Mining | | Total Reserves |
|---|---|---|---|---|---|
| | Depth (m) | Mt[a] | Depth (m) | Mt[b] | Mt |
| EAST BLOCK | | | | | |
| Val d'Or | 100 | 49.9 | 750 | 233.1 | 283.0 |
| Silkstone | 50 | 5.6 | 750 | 74.0 | 79.6 |
| Mynheer | 100 | 38.9 | 750 | 227.7 | 266.6 |
| | | 94.4 | | 534.8 | 629.2 |
| WEST BLOCK | | | | | |
| Val d'Or | 100 | 26.2 | 750 | 154.0 | 180.2 |
| TOTAL | | 120.6 | | 688.8 | 809.4 |

(a) From seam subcrop to 100 m depth

(b) From 100 m to 750 m depth


R. 23
R.22
Robb Road
(Secondary Road)
Gregg River
EAST
ALTERNATIVE
(52 km to HINTON)
PROPOSED ACCESS ROAD
MERCOAL WEST
McCardell Creek
MINE AREA
DUMP AREA
PROPOSED
WEST
ALTERNATIVE
(52 km to HINTON
ACCESS ROAD
McLeod
River
Mercoal Cr
MERCOAL
CONSTRUCTION CAMP
PLANT AREA
DUMP AREA
YEARS 1-5
YRS 11-15
Tailings Pond
40
MERCOAL EAST
A
144 km to HINTON
Beaverdam
40



+1600
A
1440
1420
1400
1380
1360
1340
1320
1300
~15 m
DH
ME-151-81
~100 m

### 2.1.2 The Mine Plan and Inclusion of the West Block

The proposed mine is designed to produce approximately 3 Mt of run-of-mine coal (ROM or raw coal) annually, and would have a life of 35 to 40 years. The mine plan is based on a conventional truck-shovel mining method. This would enable deployment of current and widely utilized equipment and procedures, but at the same time keep the mine plan flexible enough to accommodate changes in both operating conditions and technology.

The mining operation would proceed along the strike of the coal seams using two series of pits, the Val d'Or and the Silkmyn (Mynheer and Silkstone) pits as outlined in plan (Figure 1) and section, (Figure 2). The Mynheer and Silkstone seams are stratigraphically sufficiently close to allow their inclusion and therefore recovery, in one pit. Each pit would be developed to its economic mining depth limits, while initiating a second pit further along strike. Once the initial pit is completely abandoned it would be progressively backfilled with discard from subsequent pits. However, during the opening of the initial mining pits, there would be no in-pit backfill areas available for discard disposal. During the first 5-year, and to a lesser extent during the second 5-year period, an external discard dump located near the north end of the East block would therefore be utilized.

Mining has been analysed in detail only to year 20 as shown in five year mining-blocks in Figure 1. After year 20, the East block is estimated to have a remaining life of only 3 to 5 years due to the thinning of the Mynheer coal seam in the area. The applicant expected that the West block mine development would commence about year 20 and reach full production about year 25 of the Mercoal project. The coal processing and loadout facilities proposed for the East block mine would also be utilized for the West block mine by constructing a utility transportation corridor between the two blocks.

MML argued that it is necessary to include the West block in the mine permit area at the outset since proceeding only with the East block mine allows very little margin for contingency. It submitted that inclusion of the West block would enable it to deal with long term markets and to establish the overall scope of the project. It pointed out that prospective coal purchasers require long term contracts commensurate with the amortization and operating life of their electric power plants. A long project life would also assist in obtaining preferential financing and lower development costs, and thereby enhance the economic prospects of the project. MML further submitted that from a planning perspective, including the West block is of benefit to all concerned, including all levels of governments, other industries such as forestry and the railroads.

The conceptual mining plan for the West block is also based on a truck-shovel mining operation. Mining would proceed from the east end of the West block (closest to the loadout and processing facilities) and progress west in a series of pits, until the surface mineable reserves are exhausted. Preliminary information indicates that the West block offers 10 to 15 years of mining life. Further drilling and exploration work would be conducted for complete quantification of the reserves and detailed mine planning well in advance of scheduled mining.

The Board recognizes the constraints which steeply dipping coal seams place on pit design and selection of the mining system, and agrees that the mining scheme as proposed by MML is consistent with orderly recovery of the coal reserves and flexible enough to accommodate changes in the operating conditions and technology. It has some concerns about possible translational failures and bedding pinchout failures of the designed footwall, but notes that MML intends to carry out detailed geological mapping and monitoring and to effect design changes, when necessary, to prevent these failures.

The Board accepts that inclusion of the West block in the mine permit boundary may offer some advantages for long range planning and enhance prospects for marketing of the coal. It notes, however, that the land required for the proposed transportation corridor to the West block has not been included in the mine permit boundary, and that additional exploration

work, environmental studies and detailed mine planning would be necessary in order to finalize the precise mode of operation in the West block. The Board expects these matters to be addressed during the licencing stage for the West block, and would condition the permit accordingly.

While the Board is not convinced that the implied contractual commitment of 2 Mta by potential customers demonstrates a need for dedicating larger reserves of coal to the minesite than are contained within the East block, it nevertheless recognizes that there may be some debt financing advantages with greater committed coal reserves, and there also may be other land-use planning advantages. On this basis it is prepared to include the West block in the permit area.

2.1.3 Economic Stripping Ratio and Mining Depths

MML submitted that economic factors limit the average mining depths of the Val d'Or and Silkmyn pits to 75 m and 70 m, respectively. The proposed mine plan design is based on an average stripping ratio[2] of 5:1 BCM/t raw coal which is perceived by MML as an economic cut-off ratio under present market conditions. MML suggested that individual pits may be deeper or shallower than the averages, but the economic stripping ratio would be constant for each pit in the East block.

Based on the proposed highwall configuration, the applicant's geotechnical analysis indicates a technical depth limit in the range of 100 m. In some of the deeper pits the economic stripping ratio and the geotechnical depth constraints are nearly equal due to favourable seam dips and/or thick coal measures. The applicant stated that if market price conditions improve, the stripping ratio would be increased and the current and future pit depths would be adjusted accordingly.

---

2. Stripping Ratio is defined as the volume of discard in BCM that must be removed to recover one tonne of coal; thus it is expressed in units of BCM/t.

At the Board's request, the applicant submitted additional information (Figure 2 and Table 3) regarding the potential increase in stripping ratio, total recoverable coal tonnage, and mine life of the East block if average working depths of the Val d'Or and Silkmyn pits were increased by 15m depth intervals to 105m and 100m, respectively. Figure 2 gives a cross-section view of the changes in pit design, and Table 3 summarizes the effect of an increasing mining depth on the 20-year mine plan of the East block. These estimates are based on a typical section (on section Line 52) of the mine, and although geotechnical constraints have not been considered, the additional mining depth of 30m or two shovel lifts is believed to be within the geotechnical limits.

After the hearing, the applicant submitted some economic information which indicates that mining to 100-105m depth would increase the capital and operating costs by approximately 13 per cent (from $235M to $265M in 1981 dollars) and 20 per cent, respectively.

TABLE 3

EFFECTS OF GREATER MINING DEPTHS ON STRIPPING RATIO, COAL RESERVES, AND WORKING LIFE OF THE EAST BLOCK

| PIT | Raw Coal Stripping Ratio (BCM:t) | | | Total Recoverable Raw Coal Reserves (in Mt) | | | Working Years of Mine due to Increased Mining Depths (Incremental Years in brackets) | | |
|---|---|---|---|---|---|---|---|---|---|
| | Original[b] Depth shown | +15m Depth Increase | +30m Depth Increase | Original Depth shown | +15m Depth Increase | +30m Depth Increase | Original Depth shown | +15m Depth Increase | +30m Depth Increase |
| Val d'Or (Estimate) | 5.8:1 | 6.9:1 | 7.6:1 | 32.6 | 38.6 | 46.6 | 10.6 | 12.5 (+1.9) | 15.1 (+4.5) |
| Silkmyn (Estimate) | 4.2:1 | 4.8:1 | 5.6:1 | 28.1 | 33.6 | 39.6 | 9.1 | 10.9 (+1.8) | 12.9 (+3.8) |
| Overall[a] Mercoal East block (Estimate) | 5.0:1 | 5.8:1 | 6.6:1 | 60.7 | 72.2 | 86.2 | 19.7 | 23.4 (+3.7) | 28.0[c] (+8.3) |

a. Based on 20-year plan area of the East block.

b. Average Mining Depths of 75m and 70m for Val d'Or and Silkmyn Pits, respectively.

c. Mine life may also be extended if coal processing plant efficiency (clean coal:raw coal) is 0.74 rather than 0.65 (section 2.2 of this report).

The Board notes that the applicant proceeded with its mine design on the assumption of an economic stripping ratio of approximately 5.0 BCM/t of raw coal over the 20-year mine plan. Had a raw coal stripping ratio of 6.6 BCM/t been chosen, (which would accrue from mining to 100-105 m depth), incremental capital investment would be modest ($30 M) but the coal reserves and operating life would be substantially increased. It is thus evident that the relationship between capital investment, operating costs and the quantity of coal available in each depth slice (additional shovel lift) must be carefully considered in order to establish the optimum depth limit. The Board also observes that, irrespective of the initial mine depth limit, the next adjacent slice of coal reserves would ordinarily yield the next-lowest-cost coal in that particular mine operation and that those next-lowest-cost coal reserves would be permanently sterilized if they are bypassed and the pit is backfilled. This irreversibility of the mining operation dictates that selection of the mine-depth limit during the initial and subsequent detailed mine design stages be subjected to careful consideration of existing and foreseeable economic and technical changes that may enhance the project viability.

The Board considers the mining economic data provided by MML for the East block to be only cursory, and would expect MML to submit detailed economic data in order to better establish the feasibility of mining to average depths of 105-100 m. It also believes that somewhat higher real prices of coal over the long run could support further extension of the mining depths, subject to technical feasibility, and result in greatly increased recoverable coal reserves. This, in turn, would extend the mine operating life, provide reliable long-term coal supplies to customers, improve opportunities for favourable financing, and promote better planning of nearby communities.

### 2.1.4 Mining of the Third Party Crown Coal Lease

The proposed mine plan involved one third party Crown Coal Lease No. 7126 (37 ha in Twp 48, R 21, Sec 17, 18 and 8) owned by Mrs. Amelia Spanach which is scheduled to be mined during the first 15 years of operation. The applicant is negotiating with Mrs. Spanach to enable the

lease reserves to form part of the mine. MML submitted that this lease would be included in the proposed mine plan but the coal reserves contained within the lease boundary would not be mined until an agreement is reached.

MML indicated that it is technically feasible to mine around the lease without any effect on the efficiency of the operation or any loss of coal to its' own leases. It acknowledged that the coal under the Spanach lease is unlikely to be recovered unless it is included with the Mercoal operation.

Amelia Spanach urged that the application be denied until such time as the applicant has acquired the third party lease. She added that if the mine permit is granted, it should be conditional upon an agreement being reached to acquire the lease. Mrs. Spanach contended that to grant the mine permit without such a condition would be to isolate her position such that it would impair her ability to negotiate on an even footing.

The proposed mine site also included portions of other third party crown coal leases to facilitate the development and operation of surface facilities. However, coal resources of these leases would not be mined by the proposed operation.

The Board notes that both parties agree on the desirability of including Mrs. Spanach's lease in the mine plan as well as on the possible coal tonnage recovery estimate from the lease. The Board agrees that this lease can not be economically mined as a separate venture and that its inclusion in the mine plan is appropriate for the efficient development of the coal resources of the province. The Board expects the parties to proceed expeditiously to work out an equitable arrangement for inclusion of the lease.

## 2.2 COAL PROCESSING

### 2.2.1 Processing Plant Design

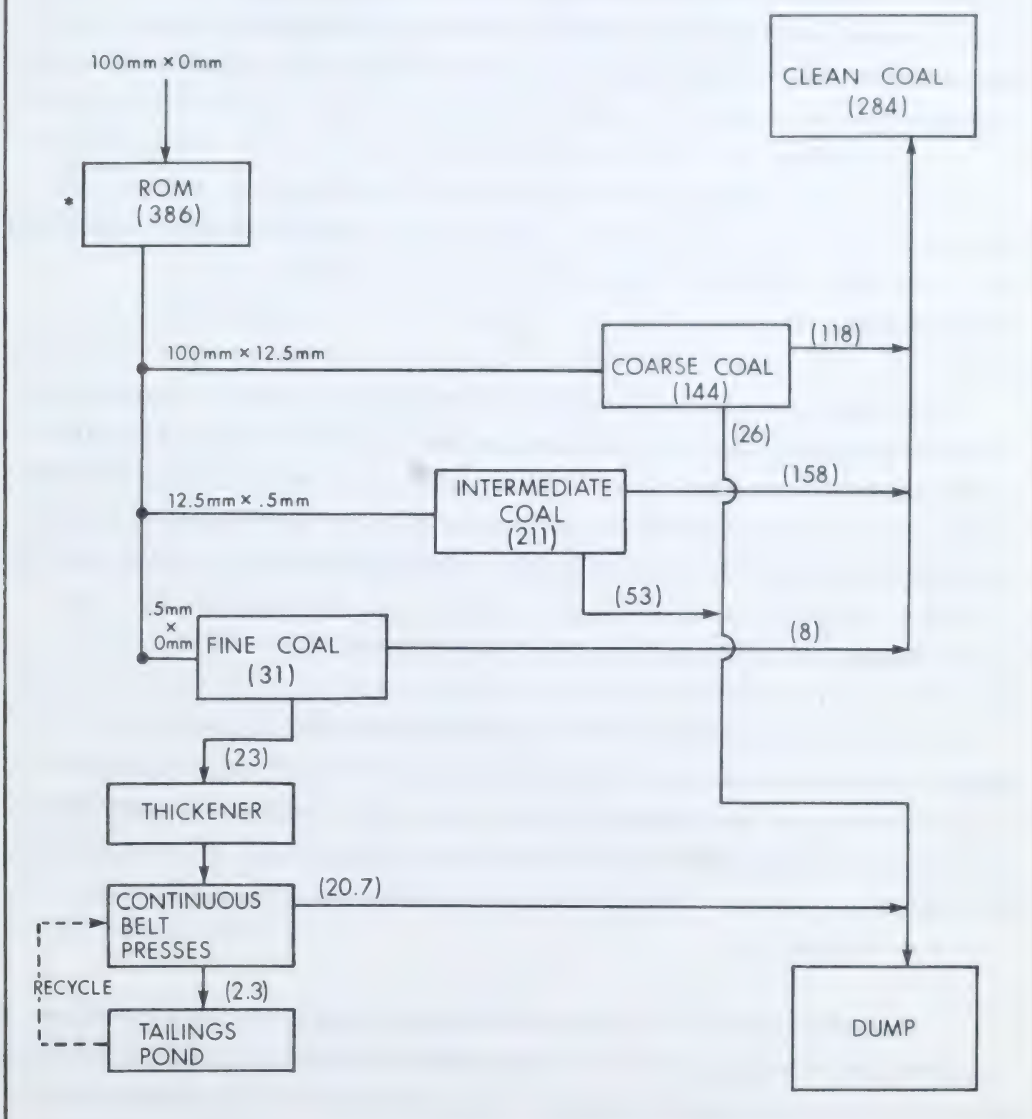
The proposed processing plant is designed to produce up to 2.2 Mta of clean coal at an overall plant yield of 65 per cent. The coal is classified as high volatile "C" bituminous thermal coal with a Hardgrove Grindability Index range of 45 to 50.

Approximately a quarter of the plant feed would be rejects and hauled to a waste dump. The applicant proposes to use continuous belt presses to dewater the 0.5 mm x 0 mm size fraction, which would form approximately 14.6 per cent (dry basis) of the raw coal feed to the plant. The applicant also proposes construction of a tailings pond to contain material that cannot be removed by mechanical means and to receive the entire tailings output during equipment breakdown or malfunction of the flocculation system.

Figure 3 shows a material balance (solids only) of an average plant feed. The run-of-mine coal would be hauled to the raw coal storage area and passed through a double roll crusher to reduce the maximum size to 100mm x 0mm. The crushed coal would be conveyed to form two stockpiles of about 10,000 t each, and would be fed to the processing plant from there.

In the plant the coarse (100mm x 12.5mm) coal would be fed to a heavy medium vessel, which would produce clean coal and rejects. The intermediate (12.5mm x 0.5mm) coal would be processed in a heavy medium cyclone system and fine coal would be treated in classifying cyclones. The resulting overflow would report to the tailings thickener and the underflow would be fed to a two-stage compound water cyclone system for recovery of additional coal.

The clean coal would be dewatered in a screen-bowl centrifuge, and refuse would be fed to a static tailings thickener. Flocculants would be




* AVERAGE FEED TO THE PLANT. (TONNES PER HOUR)

NOTE: PLANT YIELD OF 74% IS BASED ON A BLEND OF VAL D'OR AND SILKSTONE SEAMS ONLY.

FIGURE 3 PLANT MATERIAL BALANCE (SOLIDS)

added to the thickener feed and the thickened underflow, expected to be about 22 to 25 percent solids, would be dewatered in continuous belt presses. All refuse would be trucked to a designated dump area and the clean (-50mm) coal would be dried to product specification in a coal fired thermal dryer and transported to the clean coal storage and loadout facilities.

The Board considers the conceptual plant design to be satisfactory and notes that the maximum plant capacity would accommodate a variation in the plant feed, which is a desirable approach to optimum coal conservation.

The Board notes that the applicant proposes to install a double roll crusher equipped with "clay cleaning devices" to deal with the expected clay material in the plant feed. The Board notes that malfunction of these devices would demand an adjustment to the fines circuit as well as to the tailings management system. Therefore the applicant would be required to submit to the Board a report on the performance of these devices, and plant unit efficiencies after the first year of operation.

The Board observes that the application requires coarse (100mm x 12.5mm) coal to be cleaned in a three-product dense medium vessel. However, the results of tests since performed by the applicant, indicate that no appreciable amount of clean coal would be recovered from the middlings section. Thus a two-product dense medium vessel may prove more efficient.

The Board notes that the Australian Attrition Drum tests, designed to simulate the breakdown of coal in a processing plant, were not performed on the exact same size range expected. It would require the applicant to perform this test on coal samples simulating the proposed Mercoal plant feed, and submit the test results to the Board prior to the final plant design. This should confirm MML's estimate of plant feed compositions, particularly of the 100mm x 0mm size fraction.

The Board notes that the material balance shows a plant yield of approximately 74 percent, based on a 9:1 blend of Val d'Or and Silkstone seams. The Mynheer seam, however, was not included in the test work. Since this seam closely resembles the Val d'Or and Silkstone seams, it should therefore, if included in the plant feed, not drastically change the plant performance. The overall plant yield then, should be closer to 74 percent rather than to the 65 percent proposed by the applicant.

### 2.2.2 Tailings Pond Design

A tailings pond would be required to contain the material that cannot be removed by mechanical means and to accommodate tailings in the event of a mechanical breakdown of the continuous belt presses. The proposed pond would be located at the head of a local watershed, approximately 2.5 km to the south of the processing plant. The tailings material would be pumped from the plant to a discharge point in the tailings pond area, and as the tailings settle out, clarified water would be recycled to the plant.

The conceptual design envisages the pond as covering approximately 50 ha and providing storage capacity of about 5 M cubic metres, sufficient for the operating life of the East block. The applicant believes that large storage capacity is required because the technology for a completely closed circuit plant is still relatively new. It is also needed as an emergency storage area in case of mechanical failures of the solid separation circuit in the plant. However, the tailings dam would be built in stages over the life of the mining operation.

The Board notes that the applicant would be dewatering and periodically consolidating the tailings from the tailings pond. By doing this, the applicant would have a volumetric capacity available for emergencies at all times. It is also understood that the tailings pond would never be filled to capacity, since tailings would be recycled.

The Board believes that the size of the tailings pond should be kept to a practical minimum in order to avoid unnecessary environmental degradation. Since the tailings are amenable to recycling from the impoundment to the continuous belt presses, this procedure should be routinely used. The Board is prepared to approve a 5-year capacity impoundment as a first stage and would expect the applicant to examine the relative advantages of recycling versus reclamation during this period. There is a possibility that continuous belt filter press availability may improve, thus increasing the recovery of dewatered tailings at the plant. But failing this, greater tailings pond capacity may have to be considered.

2.2.3 Make-Up Water

Make-up water for the processing plant would be obtained from on-site sources and drawn from a fresh water pond located above and to the south of the tailings pond. These sources include pre-mining dewatering wells, surface run-off, and the McLeod River (only if sufficient water is not available on-site). Environmental analyses indicate that water withdrawal from the McLeod River may have detrimental environmental consequences during the low flow periods. Therefore, recharging the make-up water pond if necessary, from McLeod River, would take place only during the periods of high river flows.

In response to questions from the Crown concerning make-up water availability and requirements for emergency impoundment for additional tailings, the applicant acknowledged that water supply from on-site sources is limited and that additional water requirements would be drawn from the McLeod River. However, the applicant believes that the make-up water pond can be recharged from the McLeod River during peak flow periods. Further tests would be conducted to finalize the make-up requirements. With recharging as described, the pond would be of sufficient capacity to hold approximately one year's supply of water.

The Board concludes from data submitted, that the anticipated withdrawals of water from the McLeod River during high flow periods would have a minimal environmental impact.

## 2.3 LAND-USE CONFLICT WITH FORESTRY OPERATIONS

The proposed Mercoal project area is located within the Management Units of the Edson Forest and is part of the Forest Management Agreement (FMA) area of St. Regis (Alberta) Ltd. The common and commercially most significant tree species in the area is lodgepole pine. The Mercoal East block is over 65 percent merchantable stocked productive forest. The Mercoal West block has a smaller proportion of stocked productive forest and is characterized by potentially productive clearcut land. The proposed project would have major impact on long-term supply of timber and on the revenue to St. Regis, and would also disturb a number of growth sampling plots. However, the applicant believes that the project's conflict with the forestry operation is a question of compensation for lands used and, as such, can be resolved by negotiations between the parties concerned.

At St. Regis' request the Board accepted its evidence submitted at the McLeod River project hearing (24 to 27 August, 1982). The Board notes that although there are differences in the McLeod River and Mercoal project applications, the basic problem respecting the interrelationship of coal mining with forestry activity is substantially the same.

The Board has examined all aspects of the Mercoal development and of the conflict between this project and forestry operations, and has arrived at the same conclusion as with respect to the McLeod River Project (see ERCB Report D 83-A, dated February 1983). It believes that conflict with forestry operations can be resolved by direct negotiations between St. Regis, Mercoal Minerals Ltd., and the Department of Energy and Natural Resources.

# 3 BIOPHYSICAL MATTERS

## 3.1 DEVELOPMENT AND RECLAMATION PLANS

The applicant's proposed reclamation objective is to restore all lands disturbed by mining and associated activities to a productive state equalling that which existed prior to commencement of mining. The land is currently used for forestry operation but also has wildlife and watershed protection values. The post-mining landscape is designed to achieve the reclamation objective by careful attention to anticipated slopes, slope aspects, soils and hydrologic conditions.

### 3.1.1 The Mine Area

The mine area consists of all areas associated with the actual extraction of the coal resources. This includes the pits, drainage diversion courses around the pits, external discard dumps and haul roads. The major post mining landscape over these areas would be commercial forestry.

MML indicated that the topography of the mined out areas would be constructed in a planned and controlled manner during the backfilling operation. The result would be an area of gentle slopes with surface drainage integrated into the undisturbed perimeter areas (positive drainage). The final slope angles would be less than 15° in order to utilize tree harvesting equipment and minimize erosion. Haul roads would be reclaimed to a forested landscape component in conjunction with the pit areas. The reclaimed areas would be covered with suitable growth medium and seeded to control interim erosion.

The reclamation of the external discard dump would commence when the second lift is complete. Material replacement would entail spreading of surficial organic material (topsoil material) and/or muskeg on the side slopes and bench areas. The relatively flat crest of the completed bench of the discard dump would be treated much like the pit areas. The final slope angles would not be greater than 26°. Erosion control seeding would take place as soon as each portion is completed. Trees would be planted on the crest of the discard dump for inclusion in future forestry operation.

The salvaging and replacement of a suitable growth medium would be integrated with the stripping of pit areas. The conceptual plan submitted envisages one metre of till material followed by 15 to 30 cm of topsoil material suitable as growth medium. However, the applicant believes that more detailed sampling and analysis of individual soil units is required and that a blend of surface soils and till may provide a better growth medium.

Following the interim control period, some soil amendments would be required to begin the reforestation operation. Planting methods would follow Alberta Forest Service (AFS) standards and most of the landscape would be reforested with lodgepole pine and white spruce as principal species. Riparian habitat would be a significant landscape component associated with the Mercoal Creek and its tributaries and the discard dump ditch. Some alteration of wildlife habitat is unavoidable, but the post mining landscape would be more diverse and capable of sustaining wildlife populations.

The Board notes that the reclamation plan submitted by the applicant is conceptual, and that more detailed plans would be prepared for approval by the Development and Reclamation (D&R) review committee. It also believes that successful return of post mining landscape to commerical forestry is possible.

3.1.2 Reclamation Test Plots

In order to establish that proposed reclamation procedures are capable of achieving the desired reforestation, the first reclamation projects after mining would be to set up test plots. A small portion (approximately one hectare) of the discard dump would be constructed and reclaimed within the first two years of mining, and then carefully monitored to provide a data base on tree survival and growth which could be compared with existing forestry practice in the area. Other parameters to be examined would include actual annual growth rates, health and vigor, and soil nutrient levels.

Similar test plots would be constructed in all other mining areas and maintained for the entire life of the mine. The long term monitoring program would be designed to provide records of annual growth increments as the regenerated stands approach maturity.

When questioned by the Crown about the test plot contruction schedule, and why such plots would not be constructed earlier to collect meaningful data for the reclamation plan, the applicant responded that a 2 - 3 year earlier start would only have indicated seedling survival rates in this area. This is one of the matters already fairly clearly established. However, the applicant acknowledged that an early start would allow examination of such parameters as fertilization, water tables, and soil types.

The Board considers it important that a small number of test plots be established immediately to gather site specific data. It believes that a considerable lead could thereby be gained in proving the suitability of proposed reforestation programs.

3.1.3 Final Pit Lakes

As a natural consequence of mining, a shortage of discard material would prevent backfilling of the final pits in the East and West block mines. The applicant proposed to transform these pits into lakes.

In the East block area, the final water level would be established with the completion of drainage courses between the Val d'Or and Silkmyn pits, and between the Val d'Or pit and Embarras River. The backfill shoreline areas would be covered with a suitable growth medium and revegetated to a riparian habitat. The slopes of the final endwall and highwall of each pit would be reduced to geotechnically stable angles and configurations. Fill and weathered bedrock materials above the former highwalls and endwalls would be sloped to 27° and revegetated.

In response to questions about the source of water for the proposed lake, the applicant stated that the small portion of the Embarras River watershed in the area would fill the proposed lake and would drain into the headwaters of the Embarras River. The lake would provide opportunities for development of aquatic and semi-aquatic wildlife habitat.

The Board accepts the proposal to transform the final pits into lakes. It observes that the key to productive use of these permanent water impoundments would be careful planning and development of lakes and surrounding watershed features. Details can be accomodated during the approval process for the development and reclamation plan.

3.1.4 Plantsite, Tailings Pond and Dam Area

The applicant also proposed to reclaim the plant-site area to commerical forestry. All structures, foundations and pads would be removed, and suitable soil materials would be spread over all vacated areas. This would be followed by tree planting.

MML indicated that the tailings pond may remain as a large lake-like impoundment. Species selected for riparian habitat would be encouraged along shorelines. However, with time, the shoreline would progress towards the centre of the pond, and as desiccation of the pond continues, creation of limited wildlife habitat would become possible. In the very long term, the tailings pond would likely develop into a muskeg area.

The landscape component for the tailings dam would be wildlife habitat. Potential browse would be encouraged following erosion control seeding.

The long term stability of the reclaimed tailings pond area would depend on continued operation of channels that divert upstream drainage from the tailings ponds into the unnamed creek during the mine operation. To prevent dam erosion from the small remaining drainage area above the dam, a permanent overflow structure would be constructed.

The Board agrees with the conceptual proposal but would expect MML to undertake further studies to determine the extent to which the tailings pond could be reclaimed. Experience at other mines in Western Canada suggests considerably greater success than the applicant anticipates.

3.1.5 The West Block

The applicant stated that at this time reclamation procedures for the West block were expected to be similar to those planned for the East block.

Mining in the West block would begin in approximately 20 to 25 years, and the reclamation would follow 3 to 5 years after initial mine start up. Development and reclamation plans for the West block would therefore be addressed in detail at a later date, using experience gained from reclamation of the East block.

The Board agrees that experience gained in reclaiming the East block would assist the preparation of reclamation plans for the West block. However, it expects the applicant to prepare and submit studies which will permit a meaningful develoment and reclamation plan for the area. The Board will condition the mine permit to ensure that the work is carried out well in advance of mining in this West Block.

## 3.2 ENVIRONMENTAL IMPACT AND MONITORING

The applicant submitted a detailed outline of the biophysical impacts of the project and the mitigative measures it proposes to take to minimize such impacts. The applicant believes that there would be relatively few adverse impacts associated with the project, and early detection of such impacts is essential for effective mitigative action. It proposed to inititate an environmental monitoring program to accompany the construction, operation and maintenance, reclamation and abandonment phases of the project.

### 3.2.1 Clean Air and Impact on Summer Cottages

The construction phase would release some dust, water vapour, gases and particulates into the atmosphere, but the effect of these emissions is expected to be minor. There are about 28 summer cottage lots in the abandoned townsite area which have been leased from the Crown. The initial set-back between the cottages and the first pit operation would be approximately 1.5 km and would increase as mining proceeds eastward. The coal processing and handling facilities would be located approximately 2 km south of the cottages. The applicant considered that these set-backs offer the cottage residents adequate protection against noise and dust from the operation.

Respecting dust-emissions, mitigative measures proposed include preservation of green strips where possible, enclosure of all clean coal handling systems, and application of water on road systems. The applicant stated that to reduce vibration and noise from blasting, specific measures such as proper sequencing, timing, and minimizing the number of blasts would be adopted.

The Board recognizes the concerns of the cottage residents in the area of the proposed development, but notes that the buffer zone between the cottages and mine would progressively increase as the mining advances. It believes that the remedial measures proposed would allow reasonable

control of dust, noise and vibration, and ensure adherence to clean air quality requirements.

### 3.2.2 Potable Water Supply

MML suggested that the major impact of mining in the vicinity of the townsite is expected to be a declining water supply to summer cottage residents. Current sources in the area are natural springs, one or two tributaries of Mercoal Creek and at least one shallow well. The applicant believed that mining would reduce water flow in Mercoal Creek and could impact on the springs and well aquifer which are partly recharged by leakage from Mercoal Creek. It intended to survey the water quantity and quality of all sources available to or used by local residents prior to commencement of mining operations, and if necessary, to make alternative supplies available.

The Board notes that no permanent residents are located within the area impacted by the proposed mine. It agrees that mining would affect the quality and quantity of water available to cottages in the area, but is satisfied that the applicant's arrangements to supply potable water to residents whose present sources would be interrupted by mining should mitigate the problem.

### 3.2.3 Clean Water and Water Resources

Clean water regulations would apply to the mine, discard dump, processing plant, make-up water and tailings pond system. MML intends to establish monitoring stations at points on the perimeter of the mine where water is released from the minesite.

During the construction phase, water wells would be drilled to utilize groundwater for the construction camp, and during the operation phase, potable groundwater would be required for mine service facilities. Ground water will also provide make-up water for the processing plant. Each of these systems constitute a diversion and use of water resources. As part

of the water diversion approval requirements, the quantities of diverted water would be monitored. Similarly monitoring would be carried out for diversion of surface water and stream crossings.

The Board regards the control of all minesite run-off water and the related pit dewatering program to be of critical importance, and notes that these programs would be the subject of continuing scrutiny under the terms of a Development and Reclamation approval, and the provisions of the Clean Water Act and Water Resources Act. The Board believes such controls will be adequate to avoid undue environmental degradation.

# 4 SOCIAL MATTERS

## 4.1 A NEW ROAD

MML stated that, in the absence of a new town, the project can only proceed if commuting distances between the minesite and Hinton are shortened. It proposed two alternative routes, shown in Figure 1, either of which would significantly reduce travel time between the minesite and Hinton. On the basis of evidence at the hearing, the Board is not in a position to suggest an optimal re-alignment, but it accepts that the viability of the project would be jeopardized without improved road access. To assist the government in appraising potential developments in the area and gauging requirements for associated public infrastructure, the Board is preparing a separate report entitled "Coal Branch Regional Growth Study" which it expects to release soon (ERCB Report 83-D).

## 4.2 EMPLOYMENT AND POPULATION

The applicant stated that construction would commence in mid- 1983. Total labour requirements were estimated to be 7300 man-years, with a peak of 500 employees in mid-1984. This labour force would be housed in a self-contained camp on the project site. The number of local residents involved with construction would, in the applicant's view, be very small because subcontractors would bring their workers with them into the region, and most other skilled positions would be filled through hiring halls located outside of the region. It was submitted that some unskilled positions could be filled by local labour.

The operating workforce is expected to reach its full complement of 600 people in 1987. MML applied an employment multiplier of 1.5

which suggested that the total direct and indirect employment generated by the project in the region would be some 900 jobs. The applicant indicated that this could result in an addition of 2100 permanent residents, 90 per cent of whom would live in either Hinton or Edson, depending on how the highway system is developed in response to increased coal activity in the region.

The Metis Local 177, Smallboys Camp and Marlboro Metis Local expressed strong interest in opportunities for employment as well as for training of native people in the region. Various government initiatives that would improve matching job seekers with training opportunities and jobs were identified as being fundamental if local residents are to derive greater benefits. MML indicated its preparedness to meet with leaders of local native people to discuss the issue and to assist them where possible.

The Board believes that a continuation of the dialogue, which seems already to have been established, between MML, provincial education and manpower agencies, and interested local groups, should assist in resolving the employment concerns expressed at the hearing.

The Board is in general agreement with MML respecting regional population growth resulting from this project.

## 4.3 HOUSING

During the construction phase of the project MML proposes to use a construction camp to house the bulk of its employees, while a small number of management staff may reside in Hinton. To accommodate the operating workforce MML estimated that project-induced housing demand would be in the order of 740 units by 1987. Of these about 370 would be single-detached houses while the remainder would be apartments, attached houses, and mobile homes. Evidence presented by the applicant indicated that availability of land would not pose a problem for either Hinton or Edson. As suggested by the Town of Hinton, only the timing of land development would be a significant issue. Care would have to be taken to

ensure that no substantial municipal expenditures are incurred before they are necessary and, on the other hand, that shortages of developed land do not impose severe bottlenecks on housing availability.

The Board believes that on-going liason between project planners and municipal authorities would be the most effective means of ameliorating potential housing problems and notes that this has already been well established. While the Board believes that Hinton would attract most of the workforce from these projects, the Board recommends that other settlement options be considered by the government that may enhance the viability of the Coal Branch area as a long term source of coal supply. The Board will discuss this issue in a separate report, "Coal Branch Regional Growth Study".

## 4.4 EDUCATION AND SOCIAL SERVICES

The applicant submitted several forecasts of requirements for additional school rooms and teachers, depending on which town would receive the larger share of a population influx, and assuming various growth rates for the region as a whole. For example, it was estimated that as a result of the Mercoal project alone, as many as 19 additional classrooms may be needed in Edson between 1981 and 1987.

Given the relatively heavy capital outlays required for increased education facilities, the Board concurs with both MML and the Yellowhead School Division that adequate planning is extremely important.

The Board believes that other social services, police and fire protection, will for the most part only require some staff additions. Although these are more amenable to short-term planning, adequate monitoring of events will, nonetheless, be important. The Board will present a more detailed analysis of the timing and extent of public service expansions needed in response to anticipated mining activity in the region in a separate report.

In view of the available lead time, and having regard for the planning already undertaken by the Town of Hinton as well as for the cooperation established between MML and Hinton authorities, the Board has no reason to believe that the magnitude of this project, even in the context of other proposed developments, would impose an unmanageable burden on Hinton.

Notwithstanding this view, the Board believes that appropriate actions must be based on sound planning principles, and that municipal and provincial government departments, together with the relevant corporations, must take effective steps to analyse potential problem areas and plan accordingly.

# 5 ECONOMIC MATTERS

This section summarizes the potential market for Alberta coal and, in light of that market, evaluates the commercial viability of the project. Also discussed are the potential economic effects on the region and the province, and the net benefits which would accrue to the province. All values are in constant, 1981 dollars.

## 5.1 MARKETS FOR COAL

MML stated that one-half of the output (1 Mta) from its proposed mine is subject to a conditional agreement with the Idemitsu Kosan Co. of Japan. MML is looking to other Pacific Rim and Western European countries for profitable dispostion of the balance of its production.

MML also submitted that a buyers' market is likely to prevail in the coal industry for the next few years, and identified several contributing factors:

- the general slowdown in industrial activity in developed economies and a consequently lower demand for energy;
- the current oil surplus and its consequent effect on energy prices;
- the strength of competition from other coal-exporting countries, principally Australia and South Africa;

- the fact that some industrial users who planned conversion from oil to coal, particularly the cement industry, are already committed to other coal suppliers under long term contracts.

Despite these negative factors, MML expects to finalize contracts for its total production during 1983. Its optimism seems in part to be based on the apparent commitment by Japanese utilities to diversify their fuel requirements and to use coal as well as oil. Japanese plans were stated to include some conversion from oil to coal, installation of dual-fired capacity which would enable the use of coal or oil, and construction of units which would be fuelled by a blend of coal and oil.

As well, South Korea, Taiwan, and Hong Kong were identified as potential customers in the Pacific Rim. Here, too, growing coal demand by the utilities and cement producers was the major reason for optimism.

MML indicated that the total demand for imported thermal coal in the Pacific Basin and Asia could increase from a current level of approximately 25 Mta to between 80 and 100 Mta by 1990. The lower end of this range would reflect an average annual growth rate of about 16 per cent. In view of this rapid growth in demand for thermal coal over a relatively short time, MML thought it important to proceed with its project on schedule. It suggested that if contracts cannot be finalized now, another opportunity for pursuing long-term contracts would not present itself until after 1990.

The Board agrees that conversion from oil to coal and construction of new coal-fuelled plants in Pacific Rim countries would enhance the market potential for Alberta coal. The Board also believes that the depth and duration of the world-wide recession, the uncertain effects of variable oil prices on the timing and extent of coal conversions, and strong competition from other major coal exporters, would play significant roles in determining the ultimate penetration of Alberta coal in world markets. In the face of these factors, the Board agrees that long-term contracts could hinge on the timing of the proposed development and that expeditious action is of some

importance. However, were this project to proceed with less than adequate market commitments, accepted resource recovery conservation principles could be in jeopardy. The Board would therefore require the applicant to satisfy it that adequate marketing arrangements have been made before development begins.

## 5.2 COMMERCIAL VIABILITY

The applicant estimated that the project's capital costs would total some $235 million over its economic life[1]. At full production, in 1987, mine-operating costs were estimated to be in the range of $25 to $35/t of clean coal, or $50 to $70 million annually. One component of operating costs, labour, would be about $9/t, or $18 million per annum at full production.

In its assessment of commercial viability the applicant assumed an f.o.b.[2] mine-site price range from $45 to $55/t. Mercoal considered that recent OPEC developments portend a leveling of crude oil prices and that this would directly affect the demand and price for thermal coal. Thus, Mercoal felt it best to assume that world coal prices would only increase with world inflation and that real prices over the 16-year period of its economic analysis would remain constant. The Board believes this to be a prudent approach to the analysis.

The applicant's economic evaluation data are summarized in Table 4. Under these assumptions MML estimated that gross revenues at full production would amount to between $90 and $110 million annually.

Mercoal did not submit a detailed analysis of the commercial viability of its project and acknowledged that the stated assumptions were general to

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1 The economic analysis was based on a 16-year mine life, although Mercoal expects the actual operational life to be about 30 years.

2 f.o.b.: "free on board", i.e. transported to loadout facilities.

the point of allowing calculations of a wide range of rates of return for the project. On the basis of the evidence submitted, however, it appears that MML postulated a price and cost structure which for a 70/30 debt-equity ratio, would permit a real rate of return to equity in the order of 19 per cent. This rate of return would be achievable with something less than the average coal price, and something greater than the average operating costs submitted by the applicant. With these relatively conservative assumptions, the Board is satisfied that, given reasonable marketing opportunities, the project would be viable.

The above analysis suggests that the project would result in royalty payments of about $76 million, provincial corporate income taxes of approximately $35 million, and local taxes in the amount of $15 million, yielding a total of about $126 million of government revenue over 16 years. Since the project would ultimately operate for about 35 years, these tax contributions are seriously understated. There would, of course, be government expenditures undertaken on behalf of the project, which are discussed in following sections.

## 5.3 REGIONAL ECONOMIC IMPACT

The regional impact of the project is summarized in Column 1 of Table 5. The gross value of expenditures in the region on goods and services during project construction was estimated by the applicant to be $4 million. Of this amount only 10 per cent, or about $400 000 would accrue as wages and profits to local residents, since most goods sold in the region would be manufactured elsewhere. Local expenditures by construction workers were estimated to be about $2.4 million. Again, with a wage and profit component of 10 per cent, the value-added to the region would be in the order of $240 000 over the 3-year construction period.

The applicant defined the direct income effects during operations as the wages and salaries paid to mine employees. These were estimated to be $12.5 million per year. Indirect income effects were defined as the value of goods and services purchased for the mining operation, and were estimated to be $8.2 million per year at full production. The local value-added

component of the latter expenditure, in the form of wages and profits, was estimated to be \$820 000 per annum at full production. Thus, about \$13.3 million would annually accrue to the region in the form of wages and profits.

The applicant recognized that the population influx would require some expansion of public infrastructure. Specifically, education, health and social services, police and fire protection, and recreation services would need to be augmented prior to or during project operation. However, the applicant submitted that the cost of these services would be largely self-supporting through taxes and fees collected by the provincial and municipal governments from the increased population. The Board generally accepts that these services could be financed from personal income taxes and user fees, but believes the timing of the development will require some front-end financing.

MML stated that Hinton or Edson could face some problem in front-ending the costs of additional sewer lines, water treatment facilities, and new housing subdivisions. It was suggested that the lag between when these expenditures are required and the incremental tax revenues accrue could place an inordinate burden on current tax payers in either community. While cost-sharing programs between governments, municipal taxes, revenues from land sales, and contributions from the industrial tax transfer program were identified as alleviating potential problems, the amount and timing of funds from these sources may still be inadequate for orderly development.

In anticipation of potential problems, the Town of Hinton stated that it has developed plans in concert with other levels of government which should mitigate concerns about rapid population growth. Indeed, the Town of Hinton seems to be eagerly awaiting the prospective growth.

In its submission, the Yellowhead Regional Planning Commission recognized the beneficial aspects that mining developments would confer on the region, and supported the applicant's project as a component of that

overall development. However, it advised due caution because careful planning was needed for adequate management of all of the activities proposed for the region. In this respect, the Commission recommended that the provincial government undertake a comprehensive development strategy for the Coal Branch. To assist in this process the Board is preparing a general overview of potential development in the area. This report will be released shortly.

The Board concurs with MML and the interveners that the proposed project could bring significant economic benefits to Hinton or Edson. In view of the initiatives already taken by both communities, the Board is satisfied that short-term problems from rapid population growth could be resolved through co-ordinated planning by all levels of government and the industry. However, this would necessitate continuation of the dialogue and planning which appears to be well underway between the applicant, the towns, and other levels of government.

## 5.4 NET BENEFITS

Besides generating profits for its owners, the project would contribute to tax revenue via provincial corporate income taxes, royalties, and local taxes. All of these were considered by the applicant to be quantifiable net benefits to Alberta. As well, MML included a portion of federal corporate income taxes as an Alberta benefit. In total, the applicant estimated that these quantifiable net benefits would amount to some $268 million over the assumed 16 years period. The applicant discounted this value at rates of 5, 10 and 15 per cent, which yielded present values of $120, $49, and $13 million, respectively.

Table 5 shows the distribution of expenditures from this project accruing to other sectors of the economy.

On the cost side, the applicant assumed that indirect costs attributable to the project, such as public services for the project's labour force, would be partially offset by additional tax revenues generated by the incremental populations. Other forms of revenue sharing among various levels of government would make up any shortfall. Other public costs, such as road construction, which would be incurred on behalf of the project, were not included in the analysis. The Board generally accepts the applicant's forecast of net benefit, but rejects the notion that some portion of the federal income tax be considered as a component of that benefit. The Board therefore believes that the total undiscounted net benefit of the project would be less than $268 million.

The Board also accepts the applicant's assumption that indirect public expenditures would be generally offset by indirect and incremental tax revenues, and by other revenue sharing programs. However, the Board believes that some portion of road construction and upgrading costs should be considered a direct cost of the project.

The Board's analysis shows that provincial corporate income taxes and royalties due to the Mercoal project would amount to about $73 million over the project life and more than offset the cost of road construction and other infrasture which the Crown may have to absorb. Overall, the Board believes the project to be of significant benefit to Alberta and therefore to be in the public interest.

TABLE 4 ECONOMIC EVALUATION DATA USED BY APPLICANT

| | |
|---|---|
| Capital Costs | |
| Total Project Life | $235 million |
| Production | |
| 1985 | 0.5 Mt |
| 1986 | 1.5 Mt |
| 1987+ | 2.0 Mt |
| Operating Cost | $25 - $35/t, clean |
| Debt/Equity | 60/40 to 80/20 |
| Interest on Debt | 5 per cent, real |
| Tax Rate | |
| Federal | 36 per cent |
| Provincial | 11 per cent |
| Royalty | Existing Alberta Government Formula |
| Coal Price | |
| f.o.b. mine | $45 - $55/t |
| Evaluation Period | 16 years |

TABLE 5 BOARD ESTIMATE OF MAJOR EXPENDITURES AND REVENUES FOR THE PROJECT[a]
millions of 1981 dollars

| | 1 | 2 | 3 | 4 | 5 | 6 |
|---|---|---|---|---|---|---|
| | Expenditure in Alberta | | | | Expenditure Outside Alberta | Total |
| | Hinton and Area | Provincial Government | Other | Subtotal | | |
| **Capital Costs** | | | | | | |
| Materials and Equipment | 4 | - | 72.5 | 76.5 | 122.5 | 199 |
| Labour | 4 | - | 32.0 | 36.0 | - | 36 |
| Total | 8 | | 104.5 | 112.5 | 122.5 | 235 |
| **Operating Costs[b]** | | | | | | |
| Materials | 128 | - | 224 to 448 | 352 to 576 | 160 to 256 | 512 to 832 |
| Labour | 288 | - | - | 288 | - | 288 |
| Taxes | 15 | 35 | - | 50.0 | 115.0 | 165 |
| Royalties | - | 76 | - | 76.0 | - | 76 |
| Total | 431 | 111 | 224 to 448 | 766 to 990 | 275 to 371 | 1041 to 1361 |
| **Net Revenues** | | | | | | |
| Interest on Debt[c] | - | - | - | - | 52 | 52 |
| Returns to Equity | - | - | 134 | 134 | 34 | 168 |

(a) Premised on the applicant's evidence and excluding rail and port charges.
(b) Values are cumulative over an assumed operating life of 16 years.
(c) A 70/30 debt/equity ratio was assumed.

# 6 FINDINGS AND DECISION

## 6.1 FINDINGS

The Board, having considered all matters put before it with respect to the application, finds as follows:

(1) Most aspects of the proposed project, including the mine and processing plant site layout, the mining system, the processing plant design concept, and the sequence for backfilling and reclamation, are satisfactory.

(2) Inclusion of the West block in the mine permit boundary may assist long-range planning and coal marketing. However, the applied-for mine site makes no allowance for the proposed transportation corridor to the West block, and a detailed utility corridor plan, together with plans for mining and reclamation of this area, would be required at least 3 years before commencing operations there.

(3) Economic factors deemed to limit the average mining depths of Val d'Or and Silkmyn pits to 75m and 70m respectively are not convincing, and detailed information pertaining to the economic, technical and logistic feasibility of extending mining limits to depths of 105-100m, or more, in 15m depth increments below the initial design would be required with applications of each 5-year mine licence.

(4) Inclusion of the Mynheer coal seam in the processing plant feed is not likely to change the plant performance. In fact the plant yield would then be closer to 74 per cent than the proposed 65 per cent but further tests are required to establish this. In order to keep the tailings pond size to a practical minimum, routine recycling of tailings would be desirable.

(5) While the concepts for environmental protection appear generally adequate, the measures actually taken in practice will be monitored and controlled in accordance with the Development and Reclamation approval, Water Resources licenses, and Clean Air and Clean Water licenses administered by Alberta Environment.

(6) Impacts on commercial forestry operations can be accomodated through innovative changes to cutting cycles and changes to the FMA, but test plots should be established immediately in order to demonstrate the suitability and effectiveness of the proposed program.

(7) The project appears commercially viable and would bring significant benefits to Alberta, but suitable long-term coal marketing contracts should be secured before commencement of mine development.

## 6.2 DECISION

Having regard for its findings and responsibilities under the Coal Conservation Act, the Board is prepared, with the authorization of the Lieutenant Governor in Council, to grant the application of Mercoal Minerals Ltd.

The orders to be issued would be of the form set out in Appendices I and II of this report and would be subject to the terms and conditions contained therein, and to such other conditions as the Minister of the Environment may impose with respect to matters of the environment.

DATED at Calgary, Alberta on 7 April, 1983.

N. Berkowitz, P.Eng.
Vice Chairman

N. Strom, P.Eng.
Board Member

F. J. Mink, P.Eng.
Acting Board Member

APPENDIX I FORM OF PERMIT

THE PROVINCE OF ALBERTA

COAL CONSERVATION ACT

ENERGY RESOURCES CONSERVATION BOARD

IN THE MATTER of a surface mine of Mercoal Minerals Ltd. in the Mercoal area

PERMIT NO. C ____

WHEREAS the Energy Resources Conservation Board is prepared to grant an application by Mercoal Minerals Ltd. for a permit to develop a surface coal mine in the Mercoal area, subject to the conditions herein contained and the Deputy Minister of the Environment has given his approval hereto attached, insofar as the application affects matters of the environment; and

WHEREAS the Lieutenant Governor in Council has given his approval by Order in Council, numbered O.C. _____ and dated ____________.

THEREFORE, the Energy Resources Conservation Board, pursuant to the Coal Conservation Act, being chapter C-14 of the Revised Statutes of Alberta, 1980, hereby grants to Mercoal Minerals Ltd. (hereinafter called "the Permittee") a PERMIT to develop a surface coal mine in the Mercoal area, subject to the provisions of the Act and regulations and orders pursuant thereto and to the following terms and conditions:

1. The name of the mine site shall be Mercoal Mine and it shall be designated as Mine No.______.

2. This permit shall apply to 6920 hectares, more or less, in Townships 47, 48 and 49, Ranges 20, 21, 22 and 23, West of the 5th Meridian, as shown in Appendix A hereto attached.

3. Subject to other provisions of this permit, the mining methods, site development, and related operations shall be in accordance with:

(a) the application of the Permittee to the Energy Resources Conservation Board, registered as Application No. 820385 on April 23, 1982,

(b) subsequent information submitted to the Board as requested at the hearing and in this permit.

4. The Permittee shall carry out its operations to the satisfaction of the Board, and in a manner that

(a) will result in the mining of the practical maximum of all coal within the permit area,

(b) will not preclude or render more difficult the recovery of other coal recoverable by practical and reasonable operations, and

(c) will facilitate acceptable land reclamation.

5. Each open pit mine and external discard dump within the permit area shall be individually licensed by the Board.

6. The Permittee shall advise the Board of any proposed significant modifications to the mining plan and obtain Board approval prior to effecting such modifications.

7. The Permittee shall conduct exploration programs

(a) in the Mercoal East block area, south of line 53, to confirm the geological interpretation and to ascertain the mineability and potential coal recovery of the area, and

(b) in the Mercoal West block to confirm the correlation of all major coal seams and to ascertain the mineability and potential coal recovery of the area.

8. Prior to commencement of any construction activities or land clearing, the Permittee shall submit to the Board for its approval,

(a) mine and dump licence applications for the initial five years of operation with information pertaining to economics, technical and logistic feasibility of extending mining limits to depths of 100 metres, or more, from surface to top of the main portion of coal seams,

(b) evidence to satisfy the Board that sufficient long-term contracts for the coal production have been secured to ensure continuing commercial viability of the project.

9. The Permittee shall include with an application for a licence to commence mining operations in a pit, an economic evaluation of the limits proposed for that pit, and submit to the Board a similar evaluation prior to commencing backfilling of the pit.

10. The Permittee shall, in the early stages of mining, conduct detailed technical and economic studies respecting marginal-grade coal to determine the feasibility of stock-piling it for future use. These studies shall be submitted to the Board within two years following commencement of production.

11. The Permittee shall provide the Board with such additional geotechnical studies regarding pit-wall or discard-dump stability as may be required.

12. Three years prior to scheduled commencement of mining operations in the Mercoal West block, the Permittee shall submit details of access, a mine plan and a reclamation plan for the West block for the approval of the Board and the Department of Environment.

13. (1) The Permittee shall selectively mine all oxidized or inferior coal as may be directed by the Board, and market, store, or dispose of such coal to the satisfaction of the Board.

(2) Any plant discard coal shall be suitably disposed to the satisfaction of the Board to prevent it from becoming a safety hazard or contributing to air or water pollution.

14. The Permittee shall:

(a) upon receipt of the permit, undertake to establish test plots that will serve to demonstrate the feasibility and optimum procedures respecting reforestation on the reclaimed lands of the permit area,

(b) dispose of overburden discard in a manner approved by the Board,

(c) salvage from site clearing, stripping, and mining operations sufficient regolith suitable as a growth medium for use in any subsequent reclamation program, to the satisfaction of the Board and the Land Surface Conservation and Reclamation Council.

15. (1) Insofar as it affects matters of the environment, the application is subject to the approval of the Deputy Minister of the Environment.

(2) The approval of the Deputy Minister of the Environment, in accordance with subclause (1), is attached hereto as Appendix B, and this permit is subject to the terms and conditions therein contained.

16. (1) Attached hereto as Appendix C, and made part of this permit, is the order of the Lieutenant Governor in Council authorizing the granting of this permit.

(2) This permit is subject to the terms and conditions, if any, prescribed by the order of the Lieutenant Governor in Council set out in Appendix C.

17. The Board may, at any time

(a) cancel or suspend this permit, in whole or in part, for failure of the Permittee to comply with any provision of the Act, the regulations or the terms and conditions set out herein; or

(b) amend this permit, or make such other order as it thinks appropriate under the circumstances.

MADE at the City of Calgary, in the Province of Alberta, this

ENERGY RESOURCES CONSERVATION BOARD

## APPENDIX II FORM OF APPROVAL

THE PROVINCE OF ALBERTA

COAL CONSERVATION ACT

ENERGY RESOURCES CONSERVATION BOARD

IN THE MATTER of a coal processing plant of Mercoal Minerals Ltd. in the Mercoal area

APPROVAL NO.C ____

WHEREAS the Energy Resources Conservation Board is prepared to grant an application by Mercoal Minerals Ltd. for an approval to construct and operate a coal processing plant in the Mercoal area, subject to the conditions herein contained, and the Deputy Minister of the Environment has given his approval, hereto attached, insofar as the application affects matters of the environment; and

WHEREAS the Lieutenant Governor in Council has given his approval by Order in Council, numbered O.C.____ and dated ____________.

THEREFORE, the Energy Resources Conservation Board, pursuant to the Coal Conservation Act, being chapter C-14 of the Revised Statutes of Alberta, 1980, hereby orders as follows:

1. The construction and operation by Mercoal Minerals Ltd. (hereinafter called "the Operator") of a coal processing plant in the Mercoal area for the production of up to a maximum of 2,200,000 tonnes of clean coal per year, as such plant is described in an application from the Operator to the

Board, registered as Application No. 820385 on April 23, 1982, is approved, subject to the terms and conditions herein contained.

2. The plant shall be designated as Coal Processing Plant No. ____ and shall be located in Township 48, Range 21 and 22, West of the 5th Meridian.

3. The Operator shall:

(a) conduct the design tests as required by the Board and submit for its approval, the final design of the processing plant including overall and unit material balances for solids and liquids;

(b) advise the Board of the disposition of the saleable output prior to commencing construction of the plant;

(c) after one year of continuous operation, submit an engineering assessment of overall and unit plant performance with added attention to mechanical and hydraulic separation of clay materials, tailings dewatering, and indicated rate of tailings slurry accumulation.

4. The Operator shall operate the plant to the satisfaction of the Board and in a manner that results in the recovery of the practical maximum marketable coal from all raw coal mined and processed.

5. (1) The fuel for the thermal drier shall be derived from plant product unless the Board has authorized the use of an alternative fuel.

(2) The Operator shall conduct studies directed to the eventual use of plant discard product in a fluid bed combustor, and keep the Board informed of progress.

6. The Operator shall treat any stockpile of coal to minimize coal losses due to erosion of the stockpile by air or water.

7. The Operator shall limit the first stage construction of the tailings impoundment facility to a 5-year capacity and investigate the merits of increased recycling of tailings and keep the Board informed of progress.

8. The Operator shall advise the Board of any proposed significant modifications

(a) of the plant, or

(b) of the method or facilities employed for the storage or loading of clean coal, or

(c) in the method or facilities employed for the storage or disposal of discard material from the plant

and obtain the Board's approval therefor prior to effecting such modifications.

9. (1) Insofar as it affects matters of the environment, the application is subject to the approval of the Minister of the Environment.

(2) The approval of the Minister of the Environment, in accordance with subclause (1), is attached hereto as Appendix A, and this approval is subject to the terms and conditions therein contained.

10. (1) Attached hereto as Appendix B, and made part of this approval, is the order of the Lieutenant Governor in Council authorizing the granting of this approval.

(2) This approval is subject to the terms and conditions, if any, prescribed by the Lieutenant Governor in Council as set out in Appendix B.

11. The Board may at any time

(a) rescind or suspend this approval in whole or in part, or shut down the plant, for failure of the Operator to comply with any provision of the Act, the regulations or the terms and conditions set out herein; or

(b) amend this approval, or make such other order as it deems suitable under the circumstances.

MADE at the City of Calgary, in the Province of Alberta, this

ENERGY RESOURCES CONSERVATION BOARD